SOUTHWESTERN ENERGY CO
Form 10-Q
October 28, 2010

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 **September 30, 2010**

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.
Yesx Noo

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 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yesx No o

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 x Accelerated filer o Non-accelerated filer o Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No x

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

Class	Outstanding as of October 22, 2010
Common Stock, Par Value $0.01	346,783,295

SOUTHWESTERN ENERGY COMPANY

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FOR THE QUARTERLY PERIOD ENDED September 30, 2010

PART I FINANCIAL 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, tar

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, prices and costs 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 fund our planned capital investments;
- 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;

•

the impact of government regulation, including any increase in severance or similar taxes, legislation relating to hydraulic fracturing, the climate and over-the-counter derivatives;

•

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

•

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

•

our future property acquisition or divestiture activities;

•

the impact of the adverse outcome of any material litigation against us;

•

the effects of weather;

•

increased competition and regulation;

•

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, the risk of failure of exploration programs in areas in which oil or natural gas has not previously been discovered or produced, 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, 2009 (the 2009 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 September 30,		For the nine months ended September 30,	
	2010	2009	2010	2009
	(in thousands, except share/per share amounts)			
Operating Revenues:				
Gas sales	$ 483,886	$ 369,963	$ 1,378,873	$ 1,110,051
Gas marketing	161,324	113,642	461,576	356,652
Oil sales	3,238	1,805	10,320	4,680
Gas gathering	33,715	17,443	87,303	50,871
Other	9	96	2,160	(968)
	682,172	502,949	1,940,232	1,521,286
Operating Costs and Expenses:				
Gas purchases midstream services	158,095	112,956	457,555	353,323
Operating expenses	52,929	38,898	140,438	96,576
General and administrative expenses	35,158	31,942	104,735	84,851
Depreciation, depletion and amortization	151,284	113,833	434,307	355,988
Impairment of natural gas and oil properties				907,812
Taxes, other than income taxes	14,570	8,282	38,654	23,963
	412,036	305,911	1,175,689	1,822,513
Operating Income (Loss)	270,136	197,038	764,543	(301,227)
Interest Expense:				
Interest on debt	14,574	13,761	42,702	41,671
Other interest charges	503	740	1,447	2,269
Interest capitalized	(8,488)	(9,224)	(24,872)	(31,913)

		6,589		5,277		19,277		12,027
Other Income, Net		326		554		265		1,088
Income (Loss) Before Income Taxes		263,873		192,315		745,531		(312,166)
Provision (Benefit) for Income Taxes:								
Current		(5,274)		(20,704)		(2,574)		(56,204)
Deferred		108,509		94,809		293,690		(62,378)
		103,235		74,105		291,116		(118,582)
Net income (loss)		160,638		118,210		454,415		(193,584)
Less: Net loss attributable to noncontrolling interest		(103)		(44)		(192)		(108)
Net Income (Loss) Attributable to Southwestern Energy	$	160,741	$	118,254	$	454,607	$	(193,476)
Earnings Per Share:								
Net income (loss) attributable to Southwestern Energy stockholders Basic	$	0.47	$	0.34	$	1.32	$	(0.56)
Net income (loss) attributable to Southwestern Energy stockholders Diluted	$	0.46	$	0.34	$	1.30	$	(0.56)
Weighted Average Common Shares Outstanding:								
Basic		345,587,569		343,717,232		345,326,985		343,087,065
Diluted		349,228,576		349,000,241		349,308,957		343,087,065

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)

	September 30, 2010	December 31, 2009
ASSETS	(in thousands)	
Current Assets:		
Cash and cash equivalents	$ 14,197	$ 13,184
Restricted cash	354,176	
Accounts receivable	297,389	263,076
Inventories	30,856	30,009
Hedging asset	202,639	163,069
Other	61,939	95,163
Total Current Assets	961,196	564,501
Property and Equipment:		
Gas and oil properties, using the full cost method, including $713.2 million in 2010 and $595.4 million in 2009 excluded from amortization	7,243,413	6,329,117
Gathering systems	762,239	547,637
Other	377,002	305,030
Total property and equipment	8,382,654	7,181,784
Less: Accumulated depreciation, depletion and amortization	3,515,411	3,054,531
	4,867,243	4,127,253
Other Assets	164,285	78,496
TOTAL ASSETS	$ 5,992,724	$ 4,770,250
LIABILITIES AND EQUITY		
Current Liabilities:		
Current portion of long-term debt	$ 1,200	$ 1,200
Accounts payable	435,320	404,695
Taxes payable	24,585	25,500
Interest payable	9,967	19,775
Advances from partners	78,231	52,406
Hedging liability	9,326	20,052

Current deferred income taxes	72,527	
Other	14,986	12,788
Total Current Liabilities	646,142	536,416
Long-Term Debt	1,289,400	997,500
Other Liabilities:		
Deferred income taxes	1,061,579	811,902
Long-term hedging liability	25,751	3,057
Pension and other postretirement liabilities	11,260	12,630
Other long-term liabilities	78,091	67,764
	1,176,681	895,353
Commitments and Contingencies		
Equity:		
Southwestern Energy stockholders equity		
Common stock, $0.01 par value; authorized 1,250,000,000 shares in 2010 and 540,000,000 in 2009; issued 346,978,646 shares in 2010 and 346,081,210 in 2009	3,470	3,461
Additional paid-in capital	848,206	833,494
Retained earnings	1,868,934	1,414,327
Accumulated other comprehensive income	155,006	84,276
Common stock in treasury, 207,994 shares in 2010 and 203,830 in 2009	(4,510)	(4,333)
Total Southwestern Energy stockholders equity	2,871,106	2,331,225
Noncontrolling interest	9,395	9,756
Total Equity	2,880,501	2,340,981
TOTAL LIABILITIES AND EQUITY	$ 5,992,724	$ 4,770,250

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 nine months ended September 30,	
	2010	2009
	(in thousands)	
Cash Flows From Operating Activities		
Net income (loss)	$ 454,415	$ (193,584)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	435,515	357,218
Impairment of natural gas and oil properties		907,812
Deferred income taxes	293,690	(62,378)
Unrealized (gain) loss on derivatives	(3,504)	6,535
Stock-based compensation expense	6,612	6,859
Other	(2,173)	7,162
Change in assets and liabilities:		
Accounts receivable	(34,313)	55,546
Inventories	8,157	7,284
Accounts payable	25,090	(61,416)
Taxes payable	(915)	(10,771)
Interest payable	(9,808)	(10,943)
Advances from partners	25,825	923
Other assets and liabilities	16,471	(20,721)
Net cash provided by operating activities	1,215,062	989,526
Cash Flows From Investing Activities		
Capital investments	(1,506,079)	(1,374,047)
Proceeds from sale of property and equipment	348,379	
Transfers to restricted cash	(355,865)	
Transfers from restricted cash	1,689	
Other	(2,632)	(4,585)
Net cash used in investing activities	(1,514,508)	(1,378,632)
Cash Flows From Financing Activities		
Payments on current portion of long-term debt	(600)	(60,600)

Payments on revolving long-term debt		(2,043,600)		(879,400)
Borrowings under revolving long-term debt		2,336,100		1,164,100
Change in bank drafts outstanding		5,546		(25,783)
Proceeds from exercise of common stock options		3,013		4,171
Net cash provided by financing activities		300,459		202,488
Increase (decrease) in cash and cash equivalents		1,013		(186,618)
Cash and cash equivalents at beginning of year		13,184		196,277
Cash and cash equivalents at end of period	$	14,197	$	9,659

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	T
					(in thousands)			
Balance at December 31, 2009	346,081	$ 3,461	$ 833,494	$1,414,327	$ 84,276	$ (4,333)	$ 9,756	$ 2

Comprehensive income:								
Net income (loss)				454,607			(192)	
Change in derivatives					70,157			
Change in pension and other postretirement liabilities					573			
Total comprehensive income (loss)							(192)	
Stock-based compensation			11,708					
Exercise of stock options	899	9	3,004					
Issuance of restricted stock	20							
Cancellation of restricted stock	(21)							
Treasury stock non-qualified plan						(177)		
Distributions to noncontrolling interest in partnership							(169)	
Balance at September 30, 2010	346,979	$ 3,470	$ 848,206	$1,868,934	$ 155,006	$ (4,510)	$ 9,395	$ 2

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 September 30,		For the nine months ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Net income (loss)	$ 160,638	$ 118,210	$ 454,415	$ (193,584)
Change in derivatives:				
Reclassification to earnings [1]	(49,919)	(101,336)	(117,461)	(289,432)
Ineffectiveness [2]	253	4,969	3,358	5,021
Change in fair value of derivative instruments [3]	97,975	(5,383)	184,260	173,156
Total change in derivatives	48,309	(101,750)	70,157	(111,255)
Change in pension and other postretirement liabilities [4]	191	199	573	589
Comprehensive income (loss)	209,138	16,659	525,145	(304,250)
Less: Comprehensive loss attributable to the noncontrolling interest	(103)	(44)	(192)	(108)
Comprehensive income (loss) attributable to Southwestern Energy	$ 209,241	$ 16,703	$ 525,337	$ (304,142)

(1) Net of ($31.9), ($65.4), ($77.2) and ($180.9) million in taxes for the three months ended September 30, 2010 and 2009, and the nine months ended September 30, 2010 and 2009, respectively.

(2) Net of $0.1, $3.2, $2.1 and $3.2 million in taxes for the three months ended September 30, 2010 and 2009, and the nine months ended September 30, 2010 and 2009, respectively.

(3) Net of $62.6, ($3.5), $122.4 and $109.5 million in taxes for the three months ended September 30, 2010 and 2009, and the nine months ended September 30, 2010 and 2009, respectively.

(4) Net of $0.1, $0.1, $0.3 and $0.3 million in taxes for the three months ended September 30, 2010 and 2009, and the nine months ended September 30, 2010 and 2009, respectively.

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 AND NEW ACCOUNTING STANDARDS

Southwestern Energy Company (including its subsidiaries, collectively, the Company, Southwestern Energy, we, u 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 (E&P) and natural gas gathering and marketing (Midstream Services) through its subsidiaries. Southwestern Energy s current E&P operations are principally focused on the development of an unconventional natural gas play in Arkansas. The Company also is actively engaged in E&P activities in Texas, Pennsylvania and to a lesser extent in Oklahoma, and, in 2010, commenced an exploration program in New Brunswick, Canada. Southwestern Energy s Midstream Services business is concentrated in the core areas of its E&P operations in the United States.

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 Securities and Exchange Commission. 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 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 statement 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, 2009 (2009 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 in the Notes to the Consolidated Financial Statements included in the Company s 2009 Annual Report on Form 10-K. The Company evaluates subsequent events through the date the financial statements are issued.

On January 1, 2010, the Company implemented certain provisions of Financial Accounting Standards Board Accounting Standards Codification (FASB ASC) Topic 810, Consolidation. The new provisions (a) require a qualitative rather than a quantitative approach to determining the primary beneficiary of a variable interest entity (VIE); (b) amend certain guidance pertaining to the determination of the primary beneficiary when related parties are involved; (c) amend certain guidance for determining whether an entity is a VIE; and (d) require continuous assessments of whether an enterprise is the primary beneficiary of a VIE. The implementation did not have an impact on the Company s results of operations or financial condition.

On January 1, 2010, the Company implemented certain provisions of Accounting Standards Update No. 2010-06, Fair Value Measurements and Disclosures (Topic 820) Improving Disclosures about Fair Value Measurements (Update 2010-06). Update 2010-06 requires the Company to (a) provide information about movements of assets among Levels 1 and 2 of the three-tier fair value hierarchy; (b) provide a reconciliation of purchases, sales, issuance, and settlements of financial instruments valued with a Level 3 method; and (c) provide fair value measurement disclosures for each class of financial assets and liabilities. The implementation did not have an impact on the Company s results of operations or financial condition. Required disclosures for the reconciliation of purchases, sales, issuance and settlements of financial instruments valued with a Level 3 method are effective for the Company beginning on January 1, 2011 and the Company does not expect the implementation to have a material impact on the Company s results of operations or financial condition.

Certain reclassifications have been made to the prior year s financial statements to conform to the 2010 presentation. The effects of the reclassifications were not material to the Company s unaudited condensed consolidated financial statements.

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(2)

DIVESTITURE

In the second quarter of 2010, the Company sold certain oil and gas leases, wells and gathering equipment in East Texas for approximately $355.0 million, before customary purchase price adjustments. The sale included only producing rights to the Haynesville and Middle Bossier Shales in approximately 20,063 net acres. The net production from those intervals in this acreage was approximately 10 MMcfe per day as of April 1, 2010 and proved net reserves were approximately 31 Bcfe as of December 31, 2009. Under full cost accounting, this divestiture was accounted for as an adjustment of capitalized gas and oil properties with no gain recognized.

At closing, the Company deposited the $355.8 million of proceeds from this sale with a qualified intermediary to facilitate potential like-kind exchange transactions pursuant to Section 1031 of the Internal Revenue Code. Those funds are classified as restricted cash in the unaudited condensed consolidated balance sheet and, unless utilized for one or more like-kind exchange transactions, are restricted in their use until December 2010. In the third quarter of 2010, the Company utilized $1.7 million of the sale proceeds for like-kind exchange transactions pursuant to Section 1031 of the Internal Revenue Code. The Company expects to be subject to additional alternative minimum taxes of approximately $29.1 million in 2010 as a result of this sale if no additional like kind exchange transactions are effected.

(3)

PREPAID EXPENSES

The components of prepaid expenses included in other current assets as of September 30, 2010 and December 31, 2009 consisted of the following:

	September 30, 2010	December 31, 2009
	(in thousands)	
Prepaid drilling costs	$ 41,028	$ 53,819
Prepaid insurance	10,425	6,572
Total	$ 51,453	$ 60,391

(4)

INVENTORY

Inventory recorded in current assets includes $11.7 million at September 30, 2010 and $9.2 million at December 31, 2009, for gas in underground storage owned by the Company s E&P segment, and $19.1 million at September 30, 2010 and $20.8 million at December 31, 2009, for tubulars and other equipment used in the E&P segment.

The Company has one natural gas storage facility. The current portion of the gas is classified in inventory and carried at the lower of cost or market. During the first three months of 2009, the Company recorded a $4.3 million non-cash impairment to reduce the current portion of the Company s natural gas inventory to 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 whenever events or changes in circumstances indicate that it may not be recoverable. Withdrawals of current gas in underground storage are accounted for by a weighted average cost method whereby gas withdrawn from storage is relieved at the weighted average cost of current gas remaining in the facility.

Other Assets include $21.4 million at September 30, 2010 and $31.2 million at December 31, 2009 for non-current 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 are carried at the lower of cost or market and are accounted for by 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 class.

(5)

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 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 average price for the first-day-of-the-month during the previous 12 months, including the impact of derivatives qualifying as cash flow hedges, to calculate the ceiling value of their reserves.

Using the average price for the first-day-of-the-month during the previous 12 months for Henry Hub natural gas of $4.41 per MMBtu and $73.85 per barrel for West Texas Intermediate oil, adjusted for market differentials and the impact of derivatives qualifying as cash flow hedges, the Company s net book value of natural gas and oil properties did not exceed the ceiling amount and did not result in a ceiling test impairment at September 30, 2010. Cash flow hedges of gas production in place increased the ceiling value by approximately $159.3 million at September 30, 2010. Decreases in market prices as well as changes in production rates, levels of reserves, evaluation of costs excluded from amortization, future development costs and production costs could result in future ceiling test impairments.

At March 31, 2009, the ceiling value of the Company s reserves was calculated based upon the March 31, 2009 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 and the impact of derivatives qualifying as cash flow hedges. At March 31, 2009, the net capitalized costs of the Company s gas and oil properties exceeded the ceiling by approximately $558.3 million (net of tax) and resulted in a non-cash ceiling test impairment in the first quarter of 2009.

(6)

EARNINGS PER SHARE

The following table presents the computation of earnings per share for the three- and nine-month periods ended September 30, 2010 and 2009:

	For the three months ended September 30,		For the nine months ended September 30,	
	2010	2009	2010	2009
Net income (loss) attributable to Southwestern Energy (in thousands)	$ 160,741	$ 118,254	$ 454,607	$ (193,476)
Number of common shares:				
Weighted average outstanding	345,587,569	343,717,232	345,326,985	343,087,065
Issued upon assumed exercise of outstanding stock options	3,438,923	4,859,651	3,747,293	
Effect of issuance of nonvested restricted common stock	202,084	423,358	234,679	
Weighted average and potential dilutive outstanding(1)	349,228,576	349,000,241	349,308,957	343,087,065
Earnings per share:				
Net income (loss) attributable to Southwestern Energy stockholders - basic	$ 0.47	$ 0.34	$ 1.32	$ (0.56)
Net income (loss) attributable to Southwestern Energy stockholders - diluted	$ 0.46	$ 0.34	$ 1.30	$ (0.56)

(1)

Options for 907,284 shares and 59,153 shares of restricted stock were excluded from the calculation for the three months ended September 30, 2010 because they would have had an antidilutive effect. Options for 640,105 shares and 53,303 shares of restricted stock were excluded from the calculation for the three months ended September 30, 2009 because they would have had an antidilutive effect. Options for 510,067 shares and 12,627 shares of restricted stock were excluded from the calculation for the nine months ended September 30, 2010 because they would have had an antidilutive effect. Due to the net loss for the nine months ended September 30, 2009, options for 6,964,471 shares and 844,051 shares of restricted stock were antidilutive and excluded from the calculation.

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(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 price exposure to a portion of its projected natural gas sales. At September 30, 2010 and December 31, 2009, 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

Arrangements that 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

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.

GAAP requires that all derivatives be recognized in the balance sheet as either an asset or liability and be measured at fair value. Under GAAP, 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 either in earnings or 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 hedge accounting requirements are recorded in earnings.

The Company utilizes counterparties for its derivative instruments that it believes are credit-worthy 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 events in the financial markets in recent years demonstrate there can be no assurance that a counterparty will be able to meet its obligations to the Company.

The balance sheet classifications of the derivative financial instruments are summarized below at September 30, 2010 and December 31, 2009:

	Derivative Assets			
	September 30, 2010		December 31, 2009	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Derivatives designated as hedging instruments:				
Fixed and floating price swaps	Hedging asset	$ 138,322	Hedging asset	$ 117,553
Costless-collars	Hedging asset	64,289	Hedging asset	45,516
Fixed and floating price swaps	Other assets	17,280	Other assets	11,756
Costless-collars	Other assets	87,909	Other assets	
Total derivatives designated as hedging		$ 307,800		$ 174,825

instruments						
Derivatives not designated as hedging instruments:						
Basis swaps	Hedging asset	$	28	Hedging asset	$	
Basis swaps	Other assets		1	Other assets		
Total derivatives not designated as hedging instruments		$	29		$	
Total derivative assets		$	307,829		$	174,825

	Derivative Liabilities					
	September 30, 2010			December 31, 2009		
	Balance Sheet Classification		Fair Value	Balance Sheet Classification		Fair Value
	(in thousands)					
Derivatives designated as hedging instruments:						
Fixed and floating price swaps	Hedging liability	$	3,199	Hedging liability	$	940
Costless-collars	Hedging liability		2,184	Hedging liability		7,387
Fixed and floating price swaps	Long-term hedging liability		3,514	Long-term hedging liability		1,373
Costless-collars	Long-term hedging liability		22,237	Long-term hedging liability		
Total derivatives designated as hedging instruments		$	31,134		$	9,700
Derivatives not designated as hedging instruments:						
Basis swaps	Hedging liability	$	3,943	Hedging liability	$	11,725
Basis swaps	Long-term hedging liability			Long-term hedging liability		1,684
Total derivatives not designated as hedging instruments		$	3,943		$	13,409
Total derivative liabilities		$	35,077		$	23,109

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 instruments 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 September 30, 2010, the Company had cash flow hedges on the following volumes of natural gas production and gas-in-storage (in Bcf):

Year:	Fixed price swaps	Costless-collars
2010	36.7	7.0
2011	30.3	62.1
2012		80.5

As of September 30, 2010, the Company recorded a net gain in accumulated other comprehensive income related to its hedging activities of $165.5 million. This amount is net of a deferred income tax liability recorded as of September 30, 2010 of $105.8 million. The amount recorded in accumulated other comprehensive income will be relieved over time and recognized in earnings as the physical transactions being hedged occur. Assuming the market prices of gas futures as of September 30, 2010 remain unchanged, the Company would expect to transfer an aggregate after-tax net gain of approximately $117.4 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 $194.6 million for the nine-month period ended September 30, 2010 compared to a realized gain of $470.3 million for the nine-month period ended September 30, 2009. Volatility in earnings and other comprehensive income may occur in the future as a result of the application of the Company s derivative activities.

The following tables summarize the before tax effect of all cash flow hedges on the unaudited condensed consolidated financial statements for the three- and nine-month periods ended September 30, 2010 and 2009.

Derivative Instrument	Gain Recognized in Other Comprehensive Income (Effective Portion)			
	For the three months ended September 30,		For the nine months ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Fixed price swaps	$ 75,864	$ (6,114)	$ 166,398	$ 183,699
Costless-collars	$ 84,750	$ (2,741)	$ 140,282	$ 98,951

Derivative Instrument	Classification of Gain Reclassified from Accumulated Other Comprehensive Income into Earnings (Effective Portion)	Gain Reclassified from Accumulated Other Comprehensive Income into Earnings (Effective Portion)			
		For the three months ended September 30,		For the nine months ended September 30,	
		2010	2009	2010	2009
		(in thousands)			
Fixed price swaps	Gas Sales	$ 65,761	$ 116,216	$ 144,015	$ 282,264
Costless-collars	Gas Sales	$ 16,073	$ 50,487	$ 50,635	$ 188,060

Derivative Instrument	Classification of Gain (Loss) Recognized in Earnings (Ineffective Portion)	Gain (Loss) Recognized in Earnings (Ineffective Portion)			
		For the three months ended September 30,		For the nine months ended September 30,	
		2010	2009	2010	2009
		(in thousands)			
Fixed price swaps	Gas Sales	$ (258)	$ 4,760	$ (3,924)	$ 4,931
Costless-collars	Gas Sales	$ (157)	$ 3,415	$ (1,577)	$ 3,300

Fair Value Hedges

For fair value hedges, the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item are recognized in earnings immediately. As of September 30, 2010 and December 31, 2009, the Company had no material fair value hedges.

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. 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.

As of September 30, 2010, the Company had basis swaps on natural gas production that did not qualify for hedge accounting treatment of 10.7 Bcf and 12.0 Bcf in 2010 and 2011, respectively.

The following tables summarize the before tax effect of basis swaps that did not qualify for hedge accounting on the unaudited condensed consolidated statements of operations for the three- and nine-month periods ended September 30, 2010 and 2009.

	Unrealized Gain (Loss) Recognized in Earnings

Derivative Instrument	Income Statement Classification of Unrealized Gain (Loss)	For the three months ended September 30,		For the nine months ended September 30,	
		2010	2009	2010	2009
		(in thousands)			
Basis swaps	Gas Sales	$ 1,620	$ (8,657)	$ 9,496	$ (14,725)

Derivative Instrument	Income Statement Classification of Realized Gain (Loss)	Realized Gain (Loss) Recognized in Earnings			
		For the three months ended September 30,		For the nine months ended September 30,	
		2010	2009	2010	2009
		(in thousands)			
Basis swaps	Gas Sales	$ (2,580)	$ (4,370)	$ (9,811)	$ (3,004)

(8)

FAIR VALUE MEASUREMENTS

The carrying amounts and estimated fair values of the Company s financial instruments as of September 30, 2010 and December 31, 2009 were as follows:

	September 30, 2010		December 31, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Cash and cash equivalents	$ 14,197	$ 14,197	$ 13,184	$ 13,184
Restricted cash	$ 354,176	$ 354,176	$	$
Unsecured revolving credit facility	$ 617,000	$ 617,000	$ 324,500	$ 324,500
Senior notes	$ 673,600	$ 761,172	$ 674,200	$ 707,326
Derivative instruments	$ 272,752	$ 272,752	$ 151,716	$ 151,716

The carrying values of cash and cash equivalents, restricted cash, accounts receivable, accounts payable, other current assets and current liabilities on the unaudited condensed consolidated balance sheets approximate fair value because of their short-term nature. For debt and derivative instruments, the following methods and assumptions were used to estimate fair value:

Debt: The fair values of the Company s 7.5% Senior Notes due 2018, 7.35% Senior Notes due 2017, 7.125% Senior Notes due 2017 and 7.15% Senior Notes due 2018 were based on the market for the Company s publicly-traded debt as determined based on yield of the Company s 7.5% Senior Notes due 2018, which was 5.3% at September 30, 2010 and 6.7% at December 31, 2009. The carrying values of the borrowings under the Company s unsecured revolving

credit facility at September 30, 2010 and at December 31, 2009 approximate fair value.

Derivative Instruments: The fair value of all derivative instruments is the amount at which the instrument could be exchanged currently between willing parties. The amounts are based on quoted market prices, best estimates obtained from counterparties and an option pricing model, when necessary, for price option contracts.

GAAP 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 have 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 GAAP, the Company has classified its derivatives into these levels depending upon the data utilized to determine their fair values. The Company s Level 2 fair value measurements include fixed-price and floating-price swaps and are estimated using internal discounted cash flow calculations using the NYMEX futures index. The Company s Level 3 fair value measurements include costless-collars and basis swaps. The Company s costless-collars are valued using the Black-Scholes model, an industry standard option valuation model, and takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the NYMEX futures index, interest rates, volatility and credit worthiness. The Company s basis swaps are estimated using internal discounted cash flow calculations based upon forward commodity price curves.

Assets and liabilities measured at fair value on a recurring basis are summarized below (in thousands):

	September 30, 2010			
	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	$	$ 155,602	$ 152,227	$ 307,829
Derivative liabilities		(6,713)	(28,364)	(35,077)
Total	$	$ 148,889	$ 123,863	$ 272,752

	December 31, 2009			
	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	$	$ 129,309	$ 45,516	$ 174,825
Derivative liabilities		(2,313)	(20,796)	(23,109)
Total	$	$ 126,996	$ 24,720	$ 151,716

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- and nine-month periods ended September 30, 2010. The fair values of Level 3 derivative instruments are estimated using 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 the Company s judgment, reflect the assumptions a marketplace participant would have used at September 30, 2010.

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	For the three months ended September 30, 2010		For the nine months ended September 30, 2010	
	(in thousands)			
Balance at beginning of period	$	53,566	$	24,720
Total gains or losses (realized/unrealized):				
Included in earnings		14,956		48,743
Included in other comprehensive income		68,834		91,224
Purchases, issuances and settlements		(13,493)		(40,824)
Transfers into/out of Level 3				
Balance at September 30, 2010	$	123,863	$	123,863
Change in unrealized gains included in earnings relating to derivatives				
still held as of September 30, 2010	$	1,463	$	7,919

(9)

DEBT

The components of debt consist of the following as of September 30, 2010 and December 31, 2009:

	September 30, 2010	December 31, 2009
	(in thousands)	
Current portion of long-term debt:		
7.15% Senior Notes due 2018	$ 1,200	$ 1,200
Long-term debt:		
Variable rate (0.882% at September 30, 2010) unsecured revolving credit facility	617,000	324,500
7.5% Senior Notes due 2018	600,000	600,000
7.35% Senior Notes due 2017	15,000	15,000
7.125% Senior Notes due 2017	25,000	25,000
7.15% Senior Notes due 2018	32,400	33,000
	1,289,400	997,500
Total debt	$ 1,290,600	$ 998,700

Senior Notes and Subsidiary Guarantees

The indentures governing the Company s senior notes contain covenants that, among other things, restrict the ability of the Company and/or its subsidiaries ability to incur liens, to engage in sale and leaseback transactions and to merge, consolidate or sell assets. All of the Company s senior notes are guaranteed by its subsidiaries SEECO, Inc. (SEECO), Southwestern Energy Production Company (SEPCO) and Southwestern Energy Services Company (SES). These guarantees may be unconditionally released in certain circumstances. All of these guarantees are currently in place. Please refer to Note 16, Condensed Consolidating Financial Information , for additional information.

Credit Facility

On February 9, 2007, the Company amended its unsecured revolving credit facility (as further amended, the Credit Facility) with a syndicate of banks for which JPMorgan Chase Bank acts as the Administrative Agent. The Credit Facility expires in February 2012 and has a borrowing capacity of $1.0 billion, which may be increased to up to $1.25 billion at any time upon the Company s agreement with its existing or additional lenders. The interest rate on the Credit Facility is calculated based upon the Company s debt rating and is currently 62.5 basis points over the current London Interbank Offered Rate (LIBOR).

The Credit Facility is currently guaranteed by the Company s subsidiaries, SEECO, SEPCO and SES and requires additional subsidiary guarantors if certain guaranty coverage levels are not satisfied. The Credit Facility also contains covenants which impose certain restrictions on the Company. Under the credit agreement, the Company must keep total

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debt (as defined in the Credit Facility) at or below 60% of its total capital (as defined in the Credit Facility), must maintain a certain level of stockholders equity (as defined in the Credit Facility), and must maintain a ratio of earnings before interest, taxes, depreciation and amortization (as defined in the Credit Facility) to interest expense of 3.5 or above. There are also restrictions on the ability of the Company s subsidiaries to incur debt. At September 30, 2010, the Company was in compliance with the covenants of its debt agreements. The credit status of the financial institutions participating in the Company s Credit Facility could adversely impact its ability to borrow funds under the facility. While the Company believes all of the lenders under the Credit Facility have the ability to provide funds, it cannot predict whether each lender will be able to meet its obligation under the facility.

(10)

COMMITMENTS AND CONTINGENCIES

Commitments

In the first quarter of 2010, the Company was awarded exclusive licenses by the Province of New Brunswick in Canada to conduct an exploration program covering approximately 2.5 million acres in the province. The licenses require the Company to make certain capital investments in New Brunswick of approximately CAD $47 million in the aggregate over the next three years. In order to obtain the licenses, the Company provided promissory notes payable on demand to the Minister of Finance of the Province of New Brunswick with an aggregate principal amount of CAD $44.5 million. The promissory notes secure the Company's capital expenditure obligations under the licenses and are returnable to the Company to the extent the Company performs such obligations. If the Company fails to fully perform, the Minister of Finance may retain a portion of the applicable promissory notes in an amount equal to any deficiency. The Company commenced its Canada exploration program in 2010 and, as of September 30, 2010, no liability has been recognized in connection with the promissory notes.

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

In February 2009, the Company s subsidiary, Southwestern Energy Production Company (SEPCO), was added as a defendant in a Third Amended Original Petition in the matter of Tovah Energy, LLC and Toby Berry-Helfand v. David Michael Grimes, et, al., for which a Sixth Amended Original Petition, filed in July 2010, is now pending in the 273rd District Court in Shelby County, Texas (collectively, the Petition). In the Petition, the plaintiffs allege that, in 2005, they provided SEPCO with proprietary data regarding prospects in the James Lime formation pursuant to a confidentiality agreement (the Agreement) and that SEPCO refused to return the proprietary data to plaintiffs, subsequently acquired leases based upon such proprietary data and profited therefrom. Among other things, the plaintiffs allegations in the Petition include various statutory and common law claims, including, but not limited to claims of misappropriation of trade secrets, violation of the Texas Theft Liability Act, breach of fiduciary duty and confidential relationships, various fraud based claims and breach of contract with respect to the Agreement, including a claim of breach of a purported right of first refusal on all interests acquired by SEPCO between February 15, 2005 and February 15, 2006. Plaintiffs have claimed actual damages in excess of $55 million and, among other remedies, seek special damages, lost profits, incidental and consequential damages and punitive damages of four times the amount of actual damages established at trial. The trial has been set to begin on November 29, 2010. While the aggregate amount of plaintiff s claims could be material, management believes, based on its investigations and the advice of counsel, that the Company's ultimate liability, if any, will not be material to its consolidated financial position or results of operations. Based upon management s assessment of the merits of these claims, the Company has not accrued any amounts with respect to this lawsuit.

The Company is subject to other 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 results of operations of the Company.

(11)

INTEREST AND INCOME TAXES

The following table provides interest and income taxes paid for the three- and nine-month periods ended September 30, 2010 and 2009:

	For the three months ended September 30,				For the nine months ended September 30,			
	2010		2009		2010		2009	
	(in thousands)							
Interest payments	$	24,560	$	23,965	$	52,510	$	52,615
Income tax payments	$	14,006	$	105	$	16,706	$	105

For the nine months ended September 30, 2009, the Company received a $41.8 million income tax refund.

(12)

PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

The Company has defined pension and postretirement benefit plans which cover substantially all of the Company s employees. Net periodic pension and other postretirement benefit costs include the following components during the three- and nine-month periods ended September 30, 2010 and 2009:

	Pension Benefits							
	For the three months ended September 30,				For the nine months ended September 30,			
	2010		2009		2010		2009	
	(in thousands)							
Service cost	$	1,774	$	1,287	$	5,322	$	3,861
Interest cost		812		719		2,436		2,155
		(876)		(703)		(2,628)		(2,107)

Expected return on plan assets								
Amortization of prior service cost		87		84		260		251
Amortization of net loss		201		212		605		635
Net periodic benefit cost	$	1,998	$	1,599	$	5,995	$	4,795

	Postretirement Benefits							
	For the three months ended September 30,				For the nine month ended September 30,			
	2010		2009		2010		2009	
	(in thousands)							
Service cost	$	272	$	174	$	816	$	522
Interest cost		49		33		147		101
Amortization of transition obligation		16		16		48		48
Amortization of prior service cost		3		4		11		11
Amortization of net loss		6		2		16		6
Net periodic benefit cost	$	346	$	229	$	1,038	$	688

The Company currently expects to contribute $9.6 million to the pension plans and $0.1 million to the postretirement benefit plan in 2010. As of September 30, 2010, the Company has contributed $7.5 million to the pension plans and less than $0.1 million to the postretirement benefit plan.

The Company maintains a non-qualified deferred compensation 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 and totaled 207,994 shares at September 30, 2010 compared to 203,830 shares at December 31, 2009.

(13)

EQUITY

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 extended the term of the agreement until April 8, 2019 and amended 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.

On February 24, 2010, the Company's Board of Directors approved, and the Company and Computershare Trust Company, N.A., as rights agent, entered into, an amendment to the Rights Agreement pursuant to which the final expiration date of the rights (each as defined in the Rights Agreement) was advanced from April 8, 2019 to February 26, 2010. As a result of the amendment, the rights are no longer outstanding or exercisable.

(14)

STOCK-BASED COMPENSATION

The Company incurred the following amounts in employee stock-based compensation costs for the three and nine months ended September 30, 2010 and 2009:

	For the three months ended September 30,		For the nine months ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Stock-based compensation cost general and administrative expense	$ 2,179	$ 2,381	$ 6,612	$ 6,859
Stock-based compensation cost capitalized	$ 1,699	$ 1,426	$ 5,096	$ 4,331

As of September 30, 2010, there was $26.6 million of total unrecognized compensation cost related to the Company s unvested stock option and restricted stock grants. This cost is expected to be recognized over a weighted-average period of 2.3 years.

The following table summarizes stock option activity for the first nine months of 2010 and provides information for options outstanding as of September 30, 2010.

	Number of Options		Weighted Average Exercise Price
Outstanding at December 31, 2009	5,649,233	$	11.59
Granted	85,930		40.62
Exercised	(899,259)		3.35
Forfeited or expired	(18,879)		35.34
Outstanding at September 30, 2010	4,817,025	$	13.55
Exercisable at September 30, 2010	3,966,225	$	8.77

The following table summarizes restricted stock activity for the nine months ended September 30, 2010 and provides information for unvested shares as of September 30, 2010.

	Number of Shares		Weighted Average Grant Date Fair Value
Unvested shares at December 31, 2009	794,529	$	33.70
Granted	19,870		40.88
Vested	(105,447)		28.71

Forfeited	(21,718)		33.41
Unvested shares at September 30, 2010	687,234	$	34.68

(15)

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 the marketing of both Company and third-party produced gas volumes and through gathering fees associated with the transportation of natural gas to market.

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 2009 Annual Report on Form 10-K. Management evaluates the performance of its segments based on operating income, defined as operating revenues less operating costs and expenses. Income before income taxes, for the purpose of reconciling the operating income (loss) amount shown below to consolidated income (loss) before income taxes, is the sum of operating income (loss), interest expense and other income, net. The Other column includes items not related to the Company s reportable segments including real estate and corporate items.

	Exploration and Production		Midstream Services	Other		Total
			(in thousands)			
Three months ended September 30, 2010:						
Revenues from external customers	$ 487,133		$ 195,039	$		$ 682,172
Intersegment revenues	4,767		451,870	247		456,884
Operating income	216,696		53,390	50		270,136
Other income, net[1]	219		107			326
Depreciation, depletion and amortization expense	143,457		7,684	143		151,284
Interest expense[1]	1,701		4,888			6,589
Provision for income taxes[1]	84,257		18,957	21		103,235
Assets	4,572,128	(2)	910,506	510,090	(3)	5,992,724
Capital investments[4]	420,294		77,006	19,330		516,630

Three months ended September 30, 2009:						
Revenues from external customers	$ 371,864		$ 131,085	$		$ 502,949
Intersegment revenues	(830)		229,126	112		228,408
Operating income (loss)	172,038		25,100	(100)		197,038
Other income, net(1)	551			3		554
Depreciation, depletion and amortization expense	108,432		5,205	196		113,833
Interest expense(1)	3,819		1,458			5,277
Provision (benefit) for income taxes(1)	65,268		8,875	(38)		74,105
Assets	3,775,982	(2)	596,611	85,550	(3)	4,458,143
Capital investments(4)	333,927		64,986	9,860		408,773

	Exploration and Production		Midstream Services	Other		Total
			(in thousands)			
Nine months ended September 30, 2010:						
Revenues from external customers	$ 1,391,353		$ 548,879	$		$ 1,940,232
Intersegment revenues	14,471		1,288,531	739		1,303,741
Operating income	629,600		134,781	162		764,543
Other income, net(1)	67		186	12		265
Depreciation, depletion and amortization expense	413,069		20,831	407		434,307
Interest expense(1)	4,705		14,572			19,277
Provision for income taxes(1)	244,094		46,954	68		291,116
Assets	4,572,128	(2)	910,506	510,090	(3)	5,992,724
Capital investments(4)	1,272,953		216,025	44,802		1,533,780

Nine months ended September 30, 2009:

Revenues from external customers	$ 1,113,524	$ 407,523	$ 239	$ 1,521,286
Intersegment revenues	8,276	683,326	336	691,938
Operating income (loss)	(381,422) (5)	80,254	(59)	(301,227)
Other income, net(1)	1,079		9	1,088
Depreciation, depletion and amortization expense	341,920	13,506	562	355,988
Impairment of natural gas and oil properties	907,812			907,812
Interest expense(1)	9,671	2,356		12,027
Provision (benefit) for income taxes(1)	(148,163)	29,601	(20)	(118,582)
Assets	3,775,982 (2)	596,611	85,550 (3)	4,458,143
Capital investments(4)	1,186,409	167,442	14,350	1,368,201

(1)

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

(2)

Includes capital investments for office, technology, drilling rigs and other ancillary equipment and facilities not directly related to gas and oil property acquisition, exploration and development activities.

(3)

Other assets represent corporate assets not allocated to segments, which include the Company s restricted cash balance of $354.2 million at the three- and nine-month periods ended September 30, 2010, and assets for non-reportable segments for all periods.

(4)

Capital investments include reductions of $29.8 million and $4.2 million for the three-month periods ended September 30, 2010 and 2009, respectively, and reductions of $4.8 million and $12.4 million for the nine-month periods ended September 30, 2010 and 2009, respectively, relating to the change in accrued expenditures between periods.

(5)

The operating loss for the E&P segment for the nine months ended September 30, 2009 includes a $907.8 million non-cash ceiling test impairment of the Company s natural gas and oil properties resulting from a significant decline in natural gas prices during the first quarter of 2009.

Included in intersegment revenues of the Midstream Services segment are $394.3 million and $193.5 million for the three months ended September 30, 2010 and 2009, respectively, and $1,135.3 million and $585.2 million for the nine months ended September 30, 2010 and 2009, respectively, for marketing of the Company s E&P sales. Corporate assets include cash and cash equivalents, restricted cash, furniture and fixtures, prepaid debt and other costs. Corporate general and administrative costs, depreciation expense and taxes other than income taxes are allocated to the segments.

(16)

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 7.35% Senior Notes and 7.125% 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 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 September 30, 2010:					

Operating revenues	$		$	648,605	$	85,602	$	(52,035)	$	682,172
Operating costs and expenses:										
Gas purchases midstream services				158,503				(408)		158,095
Operating expenses				78,113		26,197		(51,381)		52,929
General and administrative expenses				31,041		4,363		(246)		35,158
Depreciation, depletion and amortization				143,202		8,082				151,284
Taxes, other than income taxes				13,014		1,556				14,570
Total operating costs and expenses				423,873		40,198		(52,035)		412,036
Operating income				224,732		45,404				270,136
Other income, net				214		112				326
Equity in earnings of subsidiaries		160,741						(160,741)		
Interest expense				1,716		4,873				6,589
Income (loss) before income taxes		160,741		223,230		40,643		(160,741)		263,873
Provision for income taxes				87,387		15,848				103,235
Net income (loss)		160,741		135,843		24,795		(160,741)		160,638
Less: Net loss attributable to noncontrolling interest				(103)						(103)
Net income (loss) attributable to Southwestern Energy	$	160,741	$	135,946	$	24,795	$	(160,741)	$	160,741
<u>Three months ended September 30, 2009:</u>										
Operating revenues	$		$	485,382	$	49,191	$	(31,624)	$	502,949
Operating costs and expenses:										

Gas purchases midstream services		113,197		(241)	112,956
Operating expenses		51,385	18,784	(31,271)	38,898
General and administrative expenses		28,740	3,314	(112)	31,942
Depreciation, depletion and amortization		108,502	5,331		113,833
Taxes, other than income taxes		7,457	825		8,282
Total operating costs and expenses		309,281	28,254	(31,624)	305,911
Operating income		176,101	20,937		197,038
Other income, net		540	14		554
Equity in earnings of subsidiaries	118,254			(118,254)	
Interest expense		3,070	2,207		5,277
Income (loss) before income taxes	118,254	173,571	18,744	(118,254)	192,315
Provision for income taxes		67,073	7,032		74,105
Net income (loss)	118,254	106,498	11,712	(118,254)	118,210
Less: Net loss attributable to noncontrolling interest		(44)			(44)
Net income (loss) attributable to Southwestern Energy	$ 118,254	$ 106,542	$ 11,712	$ (118,254)	$ 118,254

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Unaudited)

	Parent	Guarantors	Non-Guarantors (in thousands)	Eliminations	Consolidated
Nine months ended September 30, 2010:					
Operating revenues	$	$ 1,853,194	$ 227,625	$ (140,587)	$ 1,940,232
Operating costs and expenses:					
Gas purchases midstream services		458,788		(1,233)	457,555
Operating expenses		211,252	67,801	(138,615)	140,438
General and administrative expenses		91,270	14,204	(739)	104,735
Depreciation, depletion and amortization		412,217	22,090		434,307
Taxes, other than income taxes		34,461	4,193		38,654
Total operating costs and expenses		1,207,988	108,288	(140,587)	1,175,689
Operating income		645,206	119,337		764,543
Other income, net		74	191		265
Equity in earnings of subsidiaries	454,607			(454,607)	
Interest expense		5,526	13,751		19,277
Income (loss) before income taxes	454,607	639,754	105,777	(454,607)	745,531
Provision for income taxes		249,866	41,250		291,116
Net income (loss)	454,607	389,888	64,527	(454,607)	454,415
Less: Net loss attributable to noncontrolling interest		(192)			(192)
Net income (loss) attributable to	$ 454,607	$ 390,080	$ 64,527	$ (454,607)	$ 454,607

Southwestern Energy					
<u>Nine months ended September 30, 2009:</u>					
Operating revenues	$	$ 1,470,647	$ 141,507	$ (90,868)	$ 1,521,286
Operating costs and expenses:					
Gas purchases midstream services		354,129		(806)	353,323
Operating expenses		139,101	47,201	(89,726)	96,576
General and administrative expenses		75,689	9,498	(336)	84,851
Depreciation, depletion and amortization		340,846	15,142		355,988
Impairment of natural gas and oil properties		907,812			907,812
Taxes, other than income taxes		21,598	2,365		23,963
Total operating costs and expenses		1,839,175	74,206	(90,868)	1,822,513
Operating income (loss)		(368,528)	67,301		(301,227)
Other income, net		1,066	22		1,088
Equity in earnings of subsidiaries	(193,476)			193,476	
Interest expense		8,424	3,603		12,027
Income (loss) before income taxes	(193,476)	(375,886)	63,720	193,476	(312,166)
Provision (benefit) for income taxes		(142,795)	24,213		(118,582)
Net income (loss)	(193,476)	(233,091)	39,507	193,476	(193,584)
Less: Net loss attributable to noncontrolling interest		(108)			(108)

Net income (loss) attributable to Southwestern Energy	$	(193,476)	$	(232,983)	$	39,507	$	193,476	$	(193,476)

CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

		Parent		Guarantors		Non-Guarantors		Eliminations		Consolidated
						(in thousands)				
September 30, 2010:										
ASSETS										
Cash and cash equivalents	$	12,732	$	1,450	$	15	$		$	14,197
Restricted cash		354,176								354,176
Accounts receivable		29,052		250,124		18,213				297,389
Inventories				30,052		804				30,856
Other current assets		3,511		257,450		3,617				264,578
Total current assets		399,471		539,076		22,649				961,196
Intercompany receivables		1,629,953		(1,082,881)		(529,940)		(17,132)		
Investments				11,054		(11,053)		(1)		
Property and equipment		110,960		7,361,628		910,066				8,382,654
Less:		49,830		3,371,489		94,092				3,515,411

Accumulated depreciation, depletion and amortization										
		61,130		3,990,139		815,974				4,867,243
Investments in subsidiaries (equity method)		2,149,929						(2,149,929)		
Other assets		17,757		118,075		28,453				164,285
Total assets	$	4,258,240	$	3,575,463	$	326,083	$	(2,167,062)	$	5,992,724
LIABILITIES AND EQUITY										
Accounts and notes payable	$	132,793	$	327,420	$	27,992	$	(17,133)	$	471,072
Other current liabilities		3,431		169,509		2,130				175,070
Total current liabilities		136,224		496,929		30,122		(17,133)		646,142
Long-term debt		1,289,400								1,289,400
Deferred income taxes		(85,405)		1,017,819		129,165				1,061,579
Other liabilities		37,520		73,682		3,900				115,102
Total liabilities		1,377,739		1,588,430		163,187		(17,133)		3,112,223
Commitments and contingencies										
Total equity		2,880,501		1,987,033		162,896		(2,149,929)		2,880,501
Total liabilities and equity	$	4,258,240	$	3,575,463	$	326,083	$	(2,167,062)	$	5,992,724

CONDENSED CONSOLIDATING BALANCE SHEETS

(Unaudited)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
December 31, 2009:					
ASSETS					
Cash and cash equivalents	$ 7,378	$ 5,776	$ 30	$	$ 13,184
Accounts receivable	1,158	247,139	14,779		263,076
Inventories		29,156	853		30,009
Other current assets	11,510	204,131	42,591		258,232
Total current assets	20,046	486,202	58,253		564,501
Intercompany receivables	1,751,398	(1,260,932)	(474,575)	(15,891)	
Investments		10,746	(10,745)	(1)	
Property and equipment	78,733	6,429,294	673,757		7,181,784
Less: Accumulated depreciation, depletion and amortization	41,658	2,947,166	65,707		3,054,531
	37,075	3,482,128	608,050		4,127,253
Investments in subsidiaries (equity method)	1,625,645			(1,625,645)	
Other assets	20,161	20,043	38,292		78,496
Total assets	$ 3,454,325	$ 2,738,187	$ 219,275	$ (1,641,537)	$ 4,770,250
LIABILITIES AND EQUITY					
Accounts and notes payable	$ 149,485	$ 293,176	$ 24,401	$ (15,892)	$ 451,170
Other current liabilities	2,937	80,462	1,847		85,246
Total current liabilities	152,422	373,638	26,248	(15,892)	536,416

Long-term debt	997,500				997,500
Deferred income taxes	(75,222)	796,640	90,484		811,902
Other liabilities	38,644	40,265	4,542		83,451
Total liabilities	1,113,344	1,210,543	121,274	(15,892)	2,429,269
Commitments and contingencies					
Total equity	2,340,981	1,527,644	98,001	(1,625,645)	2,340,981
Total liabilities and equity	$ 3,454,325	$ 2,738,187	$ 219,275	$ (1,641,537)	$ 4,770,250

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Unaudited)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
<u>Nine months ended September 30, 2010:</u>					
Net cash provided by (used in) operating activities	$ (46,565)	$ 1,082,585	$ 179,042	$	$ 1,215,062
Investing activities:					
Capital investments	(33,915)	(1,231,500)	(240,664)		(1,506,079)
Proceeds from sale of property and equipment		347,150	1,229		348,379
Transfers to restricted cash	(355,865)				(355,865)
Transfers from restricted cash	1,689				1,689

Other	9,437	(18,440)	6,371		(2,632)
Net cash used in investing activities	(378,654)	(902,790)	(233,064)		(1,514,508)
Financing activities:					
Intercompany activities	130,114	(184,121)	54,007		
Payments on current portion of long-term debt	(600)				(600)
Payments on revolving long-term debt	(2,043,600)				(2,043,600)
Borrowings under revolving long-term debt	2,336,100				2,336,100
Other items	8,559				8,559
Net cash provided by (used in) financing activities	430,573	(184,121)	54,007		300,459
Increase (decrease) in cash and cash equivalents	5,354	(4,326)	(15)		1,013
Cash and cash equivalents at beginning of year	7,378	5,776	30		13,184
Cash and cash equivalents at end of period	$ 12,732	$ 1,450	$ 15	$	$ 14,197
<u>Nine months ended September 30, 2009:</u>					
Net cash provided by operating activities	$ 32,924	$ 896,046	$ 60,556	$	$ 989,526
Investing activities:					
Capital investments	(10,462)	(1,170,985)	(192,600)		(1,374,047)
Other	5,466	(21,101)	11,050		(4,585)
Net cash used in investing activities	(4,996)	(1,192,086)	(181,550)		(1,378,632)

Financing activities:					
Intercompany activities	(416,805)	296,040	120,765		
Payments on current portion of long-term debt	(60,600)				(60,600)
Payments on revolving long-term debt	(879,400)				(879,400)
Borrowings under revolving long-term debt	1,164,100				1,164,100
Other items	(21,612)				(21,612)
Net cash provided by (used in) financing activities	(214,317)	296,040	120,765		202,488
Decrease in cash and cash equivalents	(186,389)		(229)		(186,618)
Cash and cash equivalents at beginning of year	195,969		308		196,277
Cash and cash equivalents at end of period	$ 9,580	$	$ 79	$	$ 9,659

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 2009 Annual Report on Form 10-K and analyzes the changes in the results of operations between the three- and nine-month periods ended September 30, 2010 and 2009. 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 2009 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 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 2009 Annual Report on Form 10-K, and Item 1A, Risk Factors in Part II in this Form 10-Q and any other Form 10-Q filed during the fiscal year. You should read the following discussion with our unaudited condensed consolidated financial statements and the related notes included in this Form 10-Q.

OVERVIEW

Background

Southwestern Energy Company is an independent energy company engaged in natural gas and crude oil exploration, development and production (E&P). We are also focused on creating and capturing additional value through our natural gas gathering and marketing businesses, which we refer to as Midstream Services. We operate principally in two segments: E&P and Midstream Services.

Our primary business is the exploration for and production of natural gas within the United States with our current operations being principally focused on development of an unconventional gas reservoir located on the Arkansas side of the Arkoma Basin, which we refer to as the Fayetteville Shale play. We are also actively engaged in exploration and production activities in Texas, Pennsylvania and to a lesser extent in Oklahoma, and, in 2010, we commenced an exploration program in New Brunswick, Canada.

We are focused on providing long-term growth in the net asset value of our business, which we achieve in our E&P business through the drillbit. 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. We expect our natural gas production volumes will continue to increase due to the ongoing development of our Fayetteville Shale play in Arkansas. The price we expect to receive for our natural gas is a critical factor in the capital investments we make in order to develop our properties and increase our production. Significant, sustained declines in natural gas prices affect our ability to market natural gas on economically attractive terms to our customers. In recent years, there has been a significant decline in natural gas prices as evidenced by New York Mercantile Exchange (NYMEX) natural gas prices ranging from a high of $13.58 per Mcf in 2008 to a low of $2.51 per Mcf in 2009. Natural gas prices fluctuate due to a variety of factors we cannot control or predict. These factors, which include increased supplies of natural gas due to greater exploration and development activities, 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 to the factors identified above, the prices we realize for our production are affected by our hedging activities as well as locational differences in market prices.

Three Months Ended September 30, 2010 Compared with Three Months Ended September 30, 2009

We reported net income attributable to Southwestern Energy of $160.7 million for the three months ended September 30, 2010, or $0.46 per diluted share, compared to net income attributable to Southwestern Energy of $118.3 million, or $0.34 per diluted share, for the comparable period in 2009.

Our natural gas and oil production increased to 105.0 Bcfe for the three months ended September 30, 2010, up 31.8 Bcfe or 44%, from the three months ended September 30, 2009. The increase in our third quarter 2010 production was primarily due to a 33.5 Bcf increase in net production from our Fayetteville Shale play as a result of our ongoing development program. The average price realized for our gas production, including the effects of hedges, decreased

approximately 8% to $4.67 per Mcf for the three months ended September 30, 2010 compared to the same period in 2009.

Operating income from our E&P segment was $216.7 million for the three months ended September 30, 2010 compared to operating income of $172.0 million for the same period in 2009. The increase in operating income was the result of the revenue impact of our 44% growth in production which was partially offset by the 8% decline in our average realized gas prices and a $76.2 million increase in operating costs and expenses that resulted from our significant production growth.

Operating income for our Midstream Services segment was $53.4 million for the three months ended September 30, 2010, up from $25.1 million for the three months ended September 30, 2009, due to an increase of $36.4 million in gathering revenues and an increase of $4.5 million in the margin generated from our natural gas marketing activities, which were partially offset by a $12.6 million increase in operating costs and expenses, exclusive of gas purchase costs, that resulted from our significant growth in volumes gathered. Volumes gathered grew to 155.7 Bcf for the three months ended September 30, 2010 compared to 93.0 Bcf for the same period in 2009.

Capital investments were $516.6 million for the three months ended September 30, 2010, of which $420.3 million was invested in our E&P segment, compared to total capital investments of $408.8 million for the same period of 2009, of which $333.9 million was invested in our E&P segment.

Nine Months Ended September 30, 2010 Compared with Nine Months Ended September 30, 2009

We reported net income attributable to Southwestern Energy of $454.6 million for the nine months ended September 30, 2010, or $1.30 per diluted share, up from a net loss attributable to Southwestern Energy of $193.5 million, or $0.56 per diluted share, for the comparable period in 2009. The loss for the nine months ended September 30, 2009 included a $907.8 million, or $558.3 million net of taxes, non-cash ceiling test impairment of our natural gas and oil properties that resulted from a significant decline in natural gas prices during the first quarter of 2009.

Our natural gas and oil production increased to 293.3 Bcfe for the nine months ended September 30, 2010, up 39% from the nine months ended September 30, 2009. The increase in 2010 production was due to an 81.8 Bcf increase in net production from our Fayetteville Shale play as a result of our ongoing development program. The average price realized for our gas production, including the effects of hedges, decreased approximately 10% to $4.76 per Mcf for the nine months ended September 30, 2010 compared to the same period in 2009.

Our E&P segment reported operating income of $629.6 million for the nine months ended September 30, 2010, up from an operating loss of $381.4 million for the nine months ended September 30, 2009. The loss for the nine months ended September 30, 2009 included a $907.8 million non-cash ceiling test impairment of our natural gas and oil properties. Excluding the $907.8 million non-cash ceiling test impairment, operating income for the first nine months of 2010 increased $103.2 million over the comparable period in 2009 as a result of the revenue impact of our 39% increase in production which was partially offset by the 10% decline in our average realized gas prices and a $180.8 million increase in operating costs and expenses that resulted from our significant production growth.

Operating income for our Midstream Services segment was $134.8 million for the nine months ended September 30, 2010, up from $80.3 million for the nine months ended September 30, 2009, due to an increase of $86.1 million in gathering revenues and an increase of $5.7 million in the margin generated from our natural gas marketing activities, which were partially offset by a $37.3 million increase in operating costs and expenses, exclusive of gas purchase costs, that resulted from our significant growth in volumes gathered. Volumes gathered grew to 421.6 Bcf for the nine months ended September 30, 2010 compared to 267.4 Bcf for the same period in 2009.

Net cash provided by operating activities increased 23% to $1,215.1 million for the nine months ended September 30, 2010 compared to $989.5 million for the same period in 2009 due to an increase in net income adjusted for non-cash expenses primarily resulting from increased revenues due to higher production volumes, combined with an increase due to changes in working capital. We had capital investments of $1,533.8 million for the nine months ended September 30, 2010, of which $1,273.0 million was invested in our E&P segment, compared to total capital investments of $1,368.2 million for the same period of 2009, of which $1,186.4 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 and stock-based compensation are discussed on a consolidated basis.

Exploration and Production

	For the three months ended September 30,		For the nine months ended September 30,	
	2010	2009	2010	2009
Revenues (in thousands)	$ 491,900	$ 371,034	$ 1,405,824	$ 1,121,800
Impairment of natural gas and oil properties (in thousands)	$	$	$	$ 907,812
Operating costs and expenses (in thousands)	$ 275,204	$ 198,996	$ 776,224	$ 595,410
Operating income (loss) (in thousands)	$ 216,696	$ 172,038	$ 629,600	$ (381,422)
Gas production (MMcf)	104,730	72,982	292,444	210,791
Oil production (MBbls)	44	29	137	95
Total production (MMcfe)	104,991	73,150	293,265	211,358
Average gas price per Mcf, including hedges	$ 4.67	$ 5.06	$ 4.76	$ 5.31
Average gas price per Mcf, excluding hedges	$ 3.91	$ 2.85	$ 4.12	$ 3.16

Average oil price per Bbl	$	74.37	$	64.20	$	75.39	$	49.47
Average unit costs per Mcfe:								
Lease operating expenses	$	0.85	$	0.76	$	0.83	$	0.76
General & administrative expenses	$	0.28	$	0.38	$	0.29	$	0.34
Taxes, other than income taxes	$	0.12	$	0.10	$	0.12	$	0.10
Full cost pool amortization	$	1.31	$	1.43	$	1.35	$	1.56

Revenues

Revenues for our E&P segment were up $120.9 million, or 33%, for the three months ended September 30, 2010 compared to the same period in 2009. Higher natural gas production volumes in the third quarter of 2010 increased revenues by $160.6 million while lower realized prices for our gas production decreased revenue by $41.1 million compared to the third quarter of 2009. E&P revenues were up $284.0 million, or 25% for the nine months ended September 30, 2010. Higher natural gas production volumes in the first nine months of 2010 increased revenues by $433.2 million while lower realized prices for our gas production decreased revenue by $158.2 million. We expect our natural gas 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 October 22, 2010, we had hedged 43.7 Bcf of our remaining 2010 gas production and gas-in-storage, 92.4 Bcf of our 2011 gas production and gas-in-storage and 80.5 Bcf of our 2012 gas production to help limit our exposure to price fluctuations. Additionally, as of October 22, 2010, our E&P segment has outstanding fair value hedges in place on 1.3 Bcf, 1.6 Bcf and 4.3 Bcf of commitments for 2010, 2011 and 2012, respectively. These fair value hedges are a mixture of floating-price swap purchases and sales relating to our gas production. 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 September 30, 2010 was up 31.8 Bcfe or 44%, from the comparable period in 2009, to 105.0 Bcfe, due to a 33.5 Bcf increase in net natural gas production from our Fayetteville Shale play as a result of our ongoing development program. Natural gas production represented nearly 100% of our total production for the three months ended September 30, 2010 and was up approximately 44% to 104.7 Bcf compared to the same period in 2009. Net production from the Fayetteville Shale was 92.3 Bcf for the three months ended September 30, 2010 compared to 58.8 Bcf for the same period in 2009. Natural gas and oil production for the nine months ended September 30, 2010 was up approximately 39% to 293.3 Bcfe, from the comparable period in 2009, primarily due to an 81.8 Bcf increase in net natural gas production from our Fayetteville Shale play as a result of our ongoing development program. Natural gas production represented nearly 100% of our total production for the nine months ended September

30, 2010 and was up approximately 39% to 292.4 Bcf compared to the same period in 2009. Net production from the Fayetteville Shale was 251.4 Bcf for the nine months ended September 30, 2010 compared to 169.6 Bcf for the same period in 2009.

Commodity Prices

The average price realized for our gas production, including the effects of hedges, decreased 8% to $4.67 per Mcf for the three months ended September 30, 2010, and decreased 10% to $4.76 per Mcf for the nine months ended September 30, 2010, as compared to the same periods in 2009. The decreases in the average price realized for the three- and nine-month periods ended September 30, 2010 as compared to the same periods in 2009 primarily reflects the decreased effect of our price hedging activities, which had a greater positive impact on our average realized gas price in 2009, despite the fact that spot gas prices, excluding hedges, were higher in 2010 (see additional discussion below). We periodically enter into various hedging and other financial arrangements with respect to a portion of our projected natural gas and crude oil production in order to ensure certain desired levels of cash flow and to minimize the impact of price fluctuations, including fluctuations in locational market differentials (we refer you to Item 3 and Note 7 to the unaudited condensed consolidated financial statements included in this Form 10-Q for additional discussion).

Our hedging activities increased the average gas price $0.76 per Mcf for the three months ended September 30, 2010 compared to an increase of $2.21 per Mcf for the same period in 2009. Our hedging activities increased the average gas price $0.64 per Mcf for the nine months ended September 30, 2010 compared to an increase of $2.15 per Mcf for the same period in 2009. Disregarding the impact of hedges, the average price received for our gas production for the nine months ended September 30, 2010 of $4.12 per Mcf was $0.96 per Mcf higher than the nine months ended September 30, 2009 and $0.47 lower than the average monthly NYMEX settlement price, primarily due to locational market differentials. We had protected approximately 56% of our gas production for the nine months ended September 30, 2010 from the impact of widening basis differentials through financial hedging activities and physical sales arrangements. At September 30, 2010, we had basis protected on approximately 51 Bcf of our remaining 2010 expected gas production through financial hedging activities and physical sales arrangements at a differential to NYMEX gas prices of approximately $0.10 per Mcf, excluding transportation and fuel charges related to gas sales. Our E&P segment receives a sales price for our natural gas at a discount to average monthly NYMEX settlement prices due to locational basis differentials, while transportation charges and fuel charges also reduce the price received. For the remainder of the year, we expect our total gas sales discount to NYMEX to be $0.45 to $0.50 per Mcf.

As of September 30, 2010, we had NYMEX fixed price hedges in place on notional volumes of 36.7 Bcf of our remaining 2010 gas production and gas-in-storage at an average price of $6.18 per MMBtu and collars in place on notional volumes of 7.0 Bcf of our remaining 2010 gas production at an average floor and ceiling price of $6.68 and $8.31 per MMBtu, respectively.

As of September 30, 2010, we had NYMEX fixed price hedges in place on notional volumes of 30.3 Bcf of our 2011 gas production and gas-in-storage and collars in place on notional volumes of 62.1 Bcf and 80.5 Bcf of our 2011 and 2012 gas production, respectively. Additionally, we have basis swaps on 10.7 Bcf for the remainder of 2010 and 12.0 Bcf for 2011, in order to reduce the effects of widening market differentials on prices we receive.

Operating Income

Operating income from our E&P segment was $216.7 million for the three months ended September 30, 2010 compared to operating income of $172.0 million for the same period in 2009. The increase in operating income was the result of the revenue impact of our 44% growth in production which was partially offset by the 8% decline in our average realized gas prices and a $76.2 million increase in operating costs and expenses that resulted from our significant production growth. Operating income from our E&P segment increased to $629.6 million for the nine months ended September 30, 2010 compared to an operating loss of $381.4 million for the same period in 2009. The loss for the nine months ended September 30, 2009 includes a $907.8 million non-cash ceiling test impairment of our natural gas and oil properties that resulted from a significant decline in natural gas prices during the first quarter of 2009. Excluding the $907.8 million non-cash ceiling test impairment, operating income for the first nine months of 2010 increased $103.2 million over the same period in 2009 as a result of the revenue impact of our 39% increase in production which was partially offset by a 10% decline in our average realized gas prices and a $180.8 million increase in operating costs and expenses that resulted from our significant production growth.

Operating Costs and Expenses

Lease operating expenses per Mcfe for our E&P segment were $0.85 for three months ended September 30, 2010 compared to $0.76 for the same period in 2009. Lease operating expenses per Mcfe for our E&P segment were $0.83 for the nine months ended September 30, 2010 compared to $0.76 for the same period in 2009. The increases in lease operating expenses per unit of production for the three- and nine-month periods ended September 30, 2010, as compared to the same periods of 2009, are primarily due to increased gathering and compression costs associated with our Fayetteville Shale operations.

General and administrative expenses per Mcfe decreased 26% to $0.28 for the three months ended September 30, 2010 and decreased 15% to $0.29 for the nine months ended September 30, 2010, reflecting the effects of our increased production volumes. In total, general and administrative expenses for our E&P segment were $29.6 million for the three months ended September 30, 2010 compared to $27.6 million for the same period in 2009, and were $86.3 million for the nine months ended September 30, 2010 compared to $72.3 million for the same period in 2009. Payroll, employee incentive compensation and other employee-related costs associated with our E&P operations increased by $2.5 million for the three months ended September 30, 2010 and $11.6 million for the nine months ended September 30, 2010 compared to the same periods in 2009 primarily as a result of the expansion of our E&P operations.

Taxes other than income taxes per Mcfe increased to $0.12 for both the three and nine months ended September 30, 2010 compared to $0.10 for the same periods in 2009. 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.

Our full cost pool amortization rate averaged $1.31 per Mcfe for the three months ended September 30, 2010 compared to $1.43 per Mcfe for the same period in 2009. The decline in the average amortization rate for the three months ended September 30, 2010 compared to the same period of 2009 was primarily the result of our lower acquisition and development costs as well as the sale of certain East Texas oil and gas leases and wells in the second quarter of 2010 as the proceeds from the sale were appropriately credited to the full cost pool. For the first nine months of 2010, our full cost pool amortization rate averaged $1.35 per Mcfe compared to $1.56 per Mcfe for the same period in 2009. The decline in the average amortization rate for the nine months ended September 30, 2010 compared to the same period of 2009 was primarily the result of the $907.8 million non-cash ceiling test impairment recorded in the first quarter of 2009 and the result of lower acquisition and development costs. The amortization rate is impacted by the timing and the 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.

Unevaluated costs excluded from amortization were $713.2 million at September 30, 2010 compared to $595.4 million at December 31, 2009. The increase in unevaluated costs since December 31, 2009 resulted from a $65.6 million increase in our undeveloped leasehold acreage and seismic costs, a $26.1 million increase in our drilling activity, a $17.0 million increase in capitalized interest and a $9.1 million increase in our exploration activities in New Brunswick, Canada.

The timing and amount of production and reserve additions 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 September 30,		For the nine months ended September 30,	
	2010	2009	2010	2009
	($ in thousands, except volumes)			
Revenues marketing	$ 561,813	$ 311,497	$ 1,611,492	$ 951,003
Revenues gathering	$ 85,096	$ 48,714	$ 225,918	$ 139,846
Gas purchases marketing	$ 552,539	$ 306,745	$ 1,591,138	$ 936,356
Operating costs and expenses	$ 40,980	$ 28,366	$ 111,491	$ 74,239
Operating income	$ 53,390	$ 25,100	$ 134,781	$ 80,254
Gas volumes marketed (Bcf)	130.2	98.3	357.0	273.9
Gas volumes gathered (Bcf)	155.7	93.0	421.6	267.4

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Revenues

Revenues from our marketing activities were up 80% to $561.8 million for the three months ended September 30, 2010 and were up 69% to $1,611.5 million for the nine months ended September 30, 2010 compared to the respective periods of 2009. The increases in marketing revenues resulted from increases in the volumes marketed combined with increases in the prices received for volumes marketed. For the three months ended September 30, 2010, volumes marketed increased 32% and the price received for volumes marketed increased 36% compared to the same period in 2009. For the nine months ended September 30, 2010, volumes marketed and the price received for volumes marketed each increased 30% compared to the same period in 2009. Increases and decreases in marketing revenues due to changes in commodity prices are largely offset by corresponding changes in gas purchase expenses. Of the total volumes marketed, production from our affiliated E&P operated wells accounted for 94% and 84% of the marketed volumes for the three months ended September 30, 2010 and 2009, respectively. For the nine months ended September 30, 2010 and 2009, production from our affiliated E&P operated wells accounted for 96% and 90% of the marketed volumes, respectively.

Revenues from our gathering activities were up 75% to $85.1 million for the three months ended September 30, 2010 and up 62% to $225.9 million for the nine months ended September 30, 2010 compared to the respective periods in 2009. The increases in gathering revenues resulted from a 67% increase in gas volumes gathered for the three months ended September 30, 2010 and a 58% increase in gas volumes gathered for the nine months ended September 30, 2010 compared to the respective periods in 2009. Substantially all of the increases in gathering revenues for the three months ended September 30, 2010 and nine months ended September 30, 2010 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 as expected.

Operating Income

Operating income from our Midstream Services segment increased to $53.4 million for the three months ended September 30, 2010 compared to $25.1 million for the same period in 2009 and increased to $134.8 million for the nine months ended September 30, 2010 compared to $80.3 million for the same period in 2009. The increases in operating income reflect the substantial increases in gas volumes gathered which primarily resulted from our increased E&P production volumes. The $28.3 million increase in operating income for the three months ended September 30, 2010 was primarily due to a $36.4 million increase in gathering revenues which was partially offset by an increase in operating costs and expenses of $12.6 million. The $54.5 million increase in operating income for nine months ended September 30, 2010 was primarily due to an $86.1 million increase in gathering revenues which was partially offset by an increase in operating costs and expenses of $37.3 million that resulted from our significant growth in volumes gathered. The remaining changes in operating income were due to changes in the margin generated by our gas marketing activities. Marketing margin increased $4.5 million for the three months ended September 30, 2010 and increased $5.7 million for the nine months ended September 30, 2010 compared to the respective periods of 2009. Margins are primarily driven by volumes of gas marketed and may fluctuate depending on the prices paid for commodities and the ultimate disposition of those commodities. 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.

Interest Expense

Interest expense, net of capitalization, increased to $6.6 million for the three months ended September 30, 2010 compared to $5.3 million for the same period in 2009. The increase in interest expense, net of capitalization, for the three-month period ended September 30, 2010 was due to our increased borrowing level combined with a decrease in capitalized interest of $0.7 million which resulted from our lower weighted average interest rate for the three-month period ended September 30, 2010 compared to the same period in 2009. Interest expense, net of capitalization, increased to $19.3 million for the nine months ended September 30, 2010 compared to $12.0 million for the same period in 2009. The increase in interest expense, net of capitalization, for the nine-month period ended September 30, 2010 was primarily due to a decrease in capitalized interest of $7.0 million which resulted from our lower weighted average interest rate for the nine-month period ended September 30, 2010 compared to the same period in 2009. We capitalized interest of $8.5 million and $24.9 million for the three- and nine-month periods ended September 30, 2010, respectively, compared to $9.2 million and $31.9 million for the same periods in 2009.

Income Taxes

Our effective tax rates were 39.0% and 38.0% for the nine months ended September 30, 2010 and 2009, respectively. For the nine months ended September 30, 2010, we recorded an income tax expense of $291.1 million compared to an income tax benefit of $118.6 million for the same period in 2009. The income tax benefit for the nine months ended September 30, 2009 primarily resulted from the $907.8 million non-cash impairment of our gas and oil properties which was recorded in the first quarter of 2009.

In the second quarter of 2010, we sold certain oil and gas leases, wells and gathering equipment in East Texas. At closing, we deposited $355.8 million of proceeds from this sale with a qualified intermediary to facilitate potential like-kind exchange transactions pursuant to Section 1031 of the Internal Revenue Code. In the third quarter of 2010, we utilized $1.7 million of the sales proceeds for like-kind exchange transactions pursuant to Section 1031 of the Internal Revenue Code. We expect to be subject to additional alternative minimum taxes of approximately $29.1 million in 2010 as a result of this sale if no additional like kind exchange transactions are effected.

The filing of the 2009 consolidated federal income tax return resulted in an alternative minimum tax loss which was eligible to be carried back to the 2008 tax year. In the third quarter of 2010, we elected to carry back the 2009 alternative minimum tax loss in order to offset alternative minimum taxes paid in 2008. This election is expected to result in a $28.6 million refund of alternative minimum taxes which is included in accounts receivable as of September 30, 2010.

Stock-Based Compensation Costs

We expensed $2.2 million and capitalized $1.7 million for stock-based compensation costs incurred during the three-month period ended September 30, 2010 compared to $2.4 million expensed and $1.4 million capitalized for the comparable period in 2009. We expensed $6.6 million and capitalized $5.1 million for stock-based compensation costs incurred during the nine-month period ended September 30, 2010 compared to $6.9 million expensed and $4.3 million capitalized for the comparable period in 2009. We refer you to Note 14 in the unaudited condensed consolidated financial statements included in this Form 10-Q for additional discussion of our equity based compensation plans.

New Accounting Standards

On January 1, 2010, we implemented certain provisions of Financial Accounting Standards Board Accounting Standards Accounting Standards Codification (FASB ASC) Topic 810, Consolidation. The new provisions (a) require a qualitative rather than a quantitative approach to determining the primary beneficiary of a variable interest entity (VIE); (b) amend certain guidance pertaining to the determination of the primary beneficiary when related parties are involved; (c) amend certain guidance for determining whether an entity is a VIE; and (d) require continuous assessments of whether an enterprise is the primary beneficiary of a VIE. The implementation did not have an impact on our results of operations or financial condition.

On January 1, 2010, we implemented certain provisions of Accounting Standards Update No. 2010-06, Fair Value Measurements and Disclosures (Topic 820) Improving Disclosures about Fair Value Measurements (Update 2010-06). Update 2010-06 requires us to (a) provide information about movements of assets among Levels 1 and 2 of the three-tier fair value hierarchy; (b) provide a reconciliation of purchases, sales, issuance, and settlements of financial instruments valued with a Level 3 method; and (c) provide fair value measurement disclosures for each class of financial assets and liabilities. The implementation did not have an impact on our results of operations or financial condition. Required disclosures for the reconciliation of purchases, sales, issuance and settlements of financial instruments valued with a Level 3 method are effective for us beginning on January 1, 2011 and we do not expect the implementation to have a material impact on our results of operations or financial condition.

LIQUIDITY AND CAPITAL RESOURCES

We depend primarily on internally-generated funds, our Credit Facility (we refer you to Note 9 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), funds accessed through debt and equity markets and other sources of financing to operate our businesses. 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, in increments or in the aggregate, to up to $1.25 billion at any time upon our agreement with our existing or additional lenders. We may also obtain additional credit capacity through entering into additional arrangements. As of September 30, 2010, we had borrowings of $617.0 million under our Credit Facility compared to $324.5 million at December 31, 2009. At September 30, 2010, the Company also had $354.2 million of restricted cash that is available to facilitate potential like-kind exchange transactions pursuant to Section 1031 of the Internal Revenue Code. Any of these funds that are not used by December 2010 for like-kind exchange transactions will be used to reduce the borrowings under the Credit Facility.

Net cash provided by operating activities increased 23% to $1,215.1 million for the nine months ended September 30, 2010 compared to $989.5 million for the same period in 2009 due to an increase in net income adjusted for non-cash expenses primarily resulting from increased revenues due to higher production volumes, combined with an increase due to changes in working capital. For the nine months ended September 30, 2010, cash generated from our operating activities funded 81% of our cash requirements for capital investments with the balance primarily funded through borrowings under our Credit Facility.

We believe that our cash and cash equivalents, restricted cash, operating cash flow and available funds under our Credit Facility will be adequate to meet our capital and operating requirements for the remainder of 2010. 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 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 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 Note 7 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 are dependent 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 write-offs for non-collectable amounts. However, any sustained inaccessibility of credit by our customers and partners could adversely impact our cash flows.

Due to the above factors, 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 were $1.5 billion for the nine months ended September 30, 2010 compared to $1.4 billion for the same period in 2009. Our E&P segment investments were $1.3 billion for the nine months ended September 30, 2010 compared to $1.2 billion for the same period in 2009. Our E&P segment capitalized internal costs of $100.1 million for the nine months ended September 30, 2010 compared to $77.3 million for the comparable period in 2009. These internal costs were directly related to acquisition, exploration and development activities and are included as part of the cost of natural gas and oil properties. The increase in internal costs capitalized is due to the addition of personnel and related costs in our exploration and development segment.

Although the remainder of our $2.1 billion capital investment program planned for 2010 is expected to be funded by cash flow from operations, borrowings from our Credit Facility and our restricted cash, we may adjust the level of

our investments dependent upon the level of cash flow generated from operations and our ability to borrow under our Credit Facility. We may also obtain additional credit capacity through an increase of the Credit Facility or entering into additional arrangements.

Financing Requirements

Our total debt outstanding was $1,290.6 million at September 30, 2010 compared to $998.7 million at December 31, 2009. Our Credit Facility has a borrowing capacity of $1.0 billion, which may be increased, in increments or in the aggregate, to up to $1.25 billion at any time upon our agreement with our existing or additional lenders. As of

September 30, 2010, we had $617.0 million outstanding under our Credit Facility with a weighted average interest rate of 0.882% compared to $324.5 million outstanding at December 31, 2009 with a weighted average interest rate of 1.106%. The interest rate on our Credit Facility is calculated based upon our public debt rating and is currently 62.5 basis points over LIBOR. In July 2010, Standard and Poor s upgraded our corporate credit rating to BBB- from BB+ and, in September 2010, Moody s upgraded our corporate credit rating to Ba1 from Ba2. 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, we must keep our total debt at or below 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. Our Credit Facility s financial covenants with respect to capitalization percentages exclude the noncontrolling interest in equity, the effects of non-cash entries that result from any full cost ceiling impairments, hedging activities and our pension and other postretirement liabilities. Therefore, under our Credit Facility our capital structure at September 30, 2010 would have been 28% debt and 72% equity. We were also in compliance with all of the covenants of our Credit Facility at September 30, 2010. Although we do not anticipate any violations of our financial covenants, our ability to comply with those covenants is dependent upon the success of our exploration and development program and upon factors beyond our control, such as the market prices for natural gas and oil. If we are unable to borrow under our Credit Facility, we would have to decrease our capital investment plans.

At September 30, 2010, our capital structure consisted of 31% debt and 69% equity. Equity at September 30, 2010 includes a gain in accumulated other comprehensive income of $165.5 million related to our hedging activities and a loss of $10.5 million related to our pension and other postretirement liabilities. The amount recorded in equity for our hedging activities is based on the current market value of our hedges at September 30, 2010 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 hedges allow us to ensure a certain level of cash flow to fund our operations. At October 22, 2010 we have hedged 43.7 Bcf of our remaining 2010 gas production and gas-in-storage, 92.4 Bcf of our expected 2011 gas production and gas-in-storage and 80.5 Bcf of our expected 2012 gas production. Additionally, as of October 22, 2010, our E&P and Midstream Services segments have outstanding fair value hedges in place on 1.4 Bcf, 1.7 Bcf and 4.4 Bcf of commitments for 2010, 2011 and 2012, respectively. These fair value hedges are a mixture of floating-price swap purchases and sales relating to our 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.

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 2009 Annual Report on Form 10-K.

Contingent Liabilities and Commitments

In the first quarter of 2010, we were awarded exclusive licenses by the Province of New Brunswick in Canada to conduct an exploration program covering approximately 2.5 million acres in the province. The licenses require us to make certain capital investments in New Brunswick of approximately CAD $47 million in the aggregate over the next three years. In order to obtain the licenses, we provided promissory notes payable on demand to the Minister of Finance of the Province of New Brunswick with an aggregate principal amount of CAD $44.5 million. The promissory notes secure our capital expenditure obligations under the licenses and are returnable to us to the extent we perform such obligations. If we fail to fully perform, the Minister of Finance may retain a portion of the applicable promissory notes

in an amount equal to any deficiency. In the second quarter of 2010 we commenced the exploration program and, as of September 30, 2010, no liability has been recognized in connection with the promissory notes.

Substantially all of our employees are covered by defined benefit and postretirement benefit plans. We currently expect to contribute approximately $9.6 million to our pension plans and $0.1 million to our postretirement benefit plan in 2010. As of September 30, 2010, we have contributed $7.5 million to our pension plans and less than $0.1 million to our postretirement benefit plan. At September 30, 2010, we recognized a liability of $11.9 million as a result of the underfunded status of our pension and other postretirement benefit plans compared to a liability of $13.3 million at December 31, 2009.

In March of 2010, the President of the United States signed into law comprehensive health care reform legislation under the Patient Protection and Affordable Care Act (HR 3590) and the Health Care Education and Affordability Reconciliation Act (HR 4872) (the Acts). The Acts contain provisions which could impact our accounting for retiree medical benefits in future periods. However, the extent of that impact, if any, cannot be determined until regulations are promulgated under the Acts and additional interpretations of the Acts become available. Elements of the Acts, the impact of which are currently not determinable, include the elimination of lifetime limits on retiree medical coverage. Based on the analysis to date of the provisions in the Acts in which the impacts are reasonably determinable, a re-measurement of our Other Postretirement Benefits is not required at this time. For further information regarding our pension and other postretirement benefit plans, we refer you to Note 12 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 our capital requirements through our Credit Facility described in Financing Requirements above. We had positive working capital of $315.1 million at September 30, 2010 compared to positive working capital of $28.1 million at December 31, 2009. Current assets increased by $396.7 million at September 30, 2010 compared to December 31, 2009, primarily due to a $354.2 million increase in restricted cash related to the sale by us of certain oil and gas leases, wells and gathering equipment in East Texas. The sale occurred in the second quarter of 2010, and we deposited the proceeds of the sale with a qualified intermediary to facilitate potential like-kind exchange transactions pursuant to Section 1031 of the Internal Revenue Code. The increase in current assets also includes a $39.6 million increase in our hedging asset. Current liabilities increased by $109.7 million at September 30, 2010 compared to December 31, 2009 primarily as a result of a $72.5 million increase in our current deferred income taxes related to our hedging activities and a $30.6 million increase in accounts 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 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. 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. We 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 our natural gas inventory to the lower of cost or market. A 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 risk. Utilization of financial products for the reduction of interest rate risks is subject to the approval of our Board of Directors. 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. Please refer to discussion of credit risk associated with commodities trading below.

Interest Rate Risk

At September 30, 2010, we had $1,290.6 million of total debt with a weighted average interest rate of 4.32%. Our revolving credit facility has a floating interest rate (0.882% at September 30, 2010). At September 30, 2010, we had $617.0 million of borrowings 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 volatility in the financial markets in recent years, 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 September 30, 2010, the fair value of our financial instruments related to natural gas production and gas-in-storage was a $267.7 million asset.

	Volume (Bcf)	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 September 30, 2010 ($ in millions)
Natural Gas:						
Fixed Price Swaps:						
2010 [(1)]	36.7	$ 6.18	$	$	$	$ 82.1

2011 (2)	30.3	$ 6.68	$	$	$	$ 67.3
Floating Price Swaps:						
2010	1.3	$ 4.97	$	$	$	$ (1.3)
2011	1.6	$ 4.99	$	$	$	$ (1.1)
2012	4.3	$ 5.69	$	$	$	$ (3.2)
Costless-Collars:						
2010	7.0	$	$ 6.68	$ 8.31	$	$ 19.1
2011	62.1	$	$ 5.09	$ 6.50	$	$ 52.9
2012	80.5	$	$ 5.50	$ 6.67	$	$ 55.8
Basis Swaps:						
2010	10.7	$	$	$	$ (0.35)	$ (2.1)
2011	12.0	$	$	$	$ (0.28)	$ (1.8)

(1)

Includes fixed-price swaps for 0.1 Bcf relating to future sales from our underground storage facility that have a fair value asset of approximately $0.2 million.

(2)

Includes fixed-price swaps for 0.3 Bcf relating to future sales from our underground storage facility that have a fair value liability of approximately $0.3 million.

At September 30, 2010, our basis swaps 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 nine months ended September 30, 2010, we recorded an unrealized gain of $9.5 million related to the basis swaps that did not qualify for hedge accounting treatment and an unrealized loss of $5.5 million 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.

At December 31, 2009, we had outstanding natural gas price swaps on total notional volumes of 36.0 Bcf in 2010 and 30.0 Bcf in 2011 for which we will receive fixed prices ranging from $6.50 to $10.04 per MMBtu. At December 31, 2009, we had outstanding fixed price basis differential swaps on 46.5 Bcf of 2010 and 9.0 Bcf of 2011 gas production that did not qualify for hedge treatment.

At December 31, 2009, we had collars in place on notional volumes of 30.0 Bcf in 2010 at an average floor and ceiling price of $6.80 and $8.43 per MMBtu, respectively.

Midstream Services

At September 30, 2010, our Midstream Services segment had outstanding fair value hedges in place on 0.1 Bcf, 0.1 Bcf and 0.1 Bcf of gas for 2010, 2011 and 2012, 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 October 2010 through March 2012 and have a net fair value asset of $0.3 million as of September 30, 2010.

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 September 30, 2010. There were no changes in our internal control over financial reporting during the three months ended September 30, 2010 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.

In February 2009, the Company s subsidiary, Southwestern Energy Production Company (SEPCO), was added as a defendant in a Third Amended Original Petition in the matter of Tovah Energy, LLC and Toby Berry-Helfand v. David Michael Grimes, et, al., for which a Sixth Amended Original Petition, filed in July 2010, is now pending in the 273rd District Court in Shelby County, Texas (collectively, the Petition). In the Petition, the plaintiffs allege that, in 2005, they provided SEPCO with proprietary data regarding prospects in the James Lime formation pursuant to a confidentiality agreement (the Agreement) and that SEPCO refused to return the proprietary data to plaintiffs, subsequently acquired leases based upon such proprietary data and profited therefrom. Among other things, the plaintiffs allegations in the Petition include various statutory and common law claims, including, but not limited to claims of misappropriation of trade secrets, violation of the Texas Theft Liability Act, breach of fiduciary duty and confidential relationships, various fraud based claims and breach of contract with respect to the Agreement, including a claim of breach of a purported right of first refusal on all interests acquired by SEPCO between February 15, 2005 and February 15, 2006. Plaintiffs have claimed actual damages in excess of $55 million and, among other remedies, seek special damages, lost profits, incidental and consequential damages and punitive damages of four times the amount of actual damages established at trial. The trial has been set to begin on November 29, 2010. While the aggregate amount of plaintiff s claims could be material, management believes, based on its investigations and the advice of counsel, that the Company's ultimate liability, if any, will not be material to its consolidated financial position or results of operations. Based upon management s assessment of the merits of these claims, the Company has not accrued any amounts with respect to this lawsuit.

The Company is subject to other 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 results of operations of the Company.

ITEM 1A. RISK FACTORS.

Other than the following additional risk factor, there were no additions or material changes to the Company s risk factors as disclosed in Item 1A of Part I in the Company s 2009 Annual Report on Form 10-K.

The recent adoption of financial reform legislation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business which could have a material adverse effect on our financial position, results of operations and cash flows.

In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act) was passed by Congress and signed into law. The new legislation requires the Commodities Futures Trading Commission (the CFTC) and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. The CFTC has proposed regulations to set position limits for certain futures and option contracts in the major energy markets. The financial reform legislation may also require us to comply with margin requirements and

with certain clearing and trade execution requirements in connection with our derivative activities. At this time it is not possible to predict whether or when the CFTC will adopt those rules or include comparable provisions in its rulemaking under the new legislation or how those rules will apply to us. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties, and such developments may affect the business relationships we have with those counterparties. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks, reduce our ability to monetize or restructure our existing derivative contracts, increase our exposure to less creditworthy counterparties and limit our access to the capital necessary to grow our business. If, as a result of the legislation and regulations, we are no longer able to use derivatives as we have in the past, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital investments. Our revenues could also be adversely affected if a consequence of the legislation and regulations is lower commodity prices. Any of these consequences could have a material adverse effect on our financial position, results of operations and cash flows.

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

Not applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES.

Not applicable.

ITEM 5. OTHER INFORMATION.

Not applicable.

ITEM 6. EXHIBITS.

(31.1)

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

(31.2)

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

(32.1)

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

(101.INS)

Interactive Data File Instance Document

(101.SCH)

Interactive Data File Schema Document

(101.CAL)

Interactive Data File Calculation Linkbase Document

(101.LAB)

Interactive Data File Label Linkbase Document

(101.PRE)

Interactive Data File Presentation Linkbase Document

(101.DEF)

Interactive Data File Definition Linkbase Document

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:	October 28, 2010	/s/ GREG D. KERLEY

Greg D. Kerley
Executive Vice President
and Chief Financial Officer