SOUTHWESTERN ENERGY CO
Form 10-Q
August 05, 2010

SOUTHWESTERN ENERGY COMPANY

INDEX TO FORM 10-Q

FOR THE QUARTERLY PERIOD ENDED June 30, 2010

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 and prices and cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with forward-looking statements, risks, uncertainties and factors that could cause our actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- the timing and extent of changes in market conditions and prices for natural gas and oil (including regional basis differentials);
- our ability to transport our production to the most favorable markets or at all;
- the timing and extent of our success in discovering, developing, producing and estimating reserves;
- the economic viability of, and our success in drilling, our large acreage position in the Fayetteville Shale play overall as well as relative to other productive shale gas plays;
- our ability to fund our planned capital investments;
- our ability to determine the most effective and economic fracture stimulation for the Fayetteville Shale formation;
- the impact of 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 and services, including pressure pumping equipment and crews in the Arkoma basin;
- our future property acquisition or divestiture activities;
- the effects of weather;
- increased competition;
- the financial impact of accounting regulations and critical accounting policies;
- the comparative cost of alternative fuels;
- conditions in capital markets, changes in interest rates and the ability of our lenders to provide us with funds as agreed;
- credit risk relating to the risk of loss as a result of non-performance by our counterparties; and
- any other factors listed in the reports we have filed and may file with the Securities and Exchange Commission (SEC).

We caution you that the forward-looking statements contained in this Form 10-Q are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of natural gas and oil. These risks include, but are not limited to, commodity price volatility, third-party interruption of sales to market, inflation, 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.

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PART I FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

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See the accompanying notes which are an integral part of these

unaudited condensed consolidated financial statements.

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See the accompanying notes which are an integral part of these

unaudited condensed consolidated financial statements.

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

	Southwestern Energy Stockholders							
	Common Stock Shares Issued	Common Stock 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)				293,866			(89)	
Change in derivatives					21,848			
Change in pension and other postretirement liabilities					382			
Total comprehensive income (loss)							(89)	
Stock-based compensation			7,830					
Exercise of stock options	214	2	1,304					
Issuance of restricted stock	12							
Cancellation of restricted stock	(16)							
Treasury stock non-qualified plan						(151)		
Distributions to noncontrolling interest in							(106)	

partnership														
Balance at June 30, 2010	346,291	$	3,463	$	842,628	$1,708,193	$	106,506	$	(4,484)	$	9,561	$	2

See the accompanying notes which are an integral part of these

unaudited condensed consolidated financial statements.

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(1) Net of ($24.5), ($61.9), ($45.3) and ($115.5) million in taxes for the three months ended June 30, 2010 and 2009, and the six months ended June 30, 2010 and 2009, respectively.

(2) Net of $2.0, $0.5, $2.0 and less than $0.1 million in taxes for the three months ended June 30, 2010 and 2009, and the six months ended June 30, 2010 and 2009, respectively.

(3) Net of $13.8, $5.2, $59.8 and $113.0 million in taxes for the three months ended June 30, 2010 and 2009, and the six months ended June 30, 2010 and 2009, respectively.

(4) Net of $0.1, $0.1, $0.2 and $0.2 million in taxes for the three months ended June 30, 2010 and 2009, and the six months ended June 30, 2010 and 2009, respectively.

See the accompanying notes which are an integral part of these

unaudited condensed consolidated financial statements.

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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 Oklahoma, Pennsylvania and Texas and commenced an exploration program in New Brunswick, Canada in 2010. 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.

(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. The Company will be subject to alternative minimum taxes totaling approximately $45 million in 2010 if no like-kind exchange transactions are effected pursuant to Section 1031 of the Internal Revenue Code.

(3) PREPAID EXPENSES

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

(4) INVENTORY

Inventory recorded in current assets includes $8.0 million at June 30, 2010 and $9.2 million at December 31, 2009, for gas in underground storage owned by the Company s E&P segment, and $21.7 million at June 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 $19.9 million at June 30, 2010 and $31.2 million at December 31, 2009 for inventory held by the Midstream Services segment consisting primarily of pipe that will be used to construct gathering systems for the Fayetteville Shale play.

Tubulars and other equipment 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

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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 $4.10 per MMBtu and $72.25 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 June 30, 2010. Cash flow hedges of gas production in place increased the ceiling value by approximately $248.3 million at June 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 our 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 six-month periods ended June 30, 2010 and 2009:

(1)

Options for 500,774 shares and 6,543 shares of restricted stock were excluded from the calculation for the three months ended June 30, 2010 because they would have had an antidilutive effect. Options for 613,142 shares and 6,798 shares of restricted stock were excluded from the calculation for the three months ended June 30, 2009 because they would have had an antidilutive effect. Options for 463,142 shares and 8,781 shares of restricted stock were excluded from the calculation for the six months ended June 30, 2010 because they would have had an antidilutive effect. Due to the net loss for the six months ended June 30, 2009, options for 7,255,311 shares and 836,113 shares of restricted stock were antidilutive and excluded from the calculation.

(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 June 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 classification of the derivative financial instruments are summarized below at June 30, 2010 and December 31, 2009:

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

As of June 30, 2010, the Company recorded a net gain in accumulated other comprehensive income related to its hedging activities of $117.2 million. These amounts are net of a deferred income tax liability recorded as of June 30, 2010 of $74.9 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 June 30, 2010 remain unchanged, the Company would expect to transfer an aggregate after-tax net gain of approximately $92.6 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 $112.8 million for the six-month period ended June 30, 2010 compared to a realized gain of $303.6 million for the six-month period ended June 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 six-month periods ended June 30, 2010 and 2009.

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 June 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 June 30, 2010, the Company had basis swaps on natural gas production that did not qualify for hedge accounting treatment of 22.1 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 six-month periods ended June 30, 2010 and 2009.

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(8) FAIR VALUE MEASUREMENTS

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

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 6.4% at June 30, 2010 and 6.7% at December 31, 2009. The carrying values of the borrowings under the Company s unsecured revolving credit facility at June 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.

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

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 six-month periods ended June 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 June 30, 2010.

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(9) DEBT

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

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 87.5 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 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 June 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.

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(10) CONTINGENCIES AND COMMITMENTS

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 June 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

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

(11) INTEREST AND INCOME TAXES

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

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(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 six-month periods ended June 30, 2010 and 2009:

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 June 30, 2010, the Company has contributed $3.6 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 207,249 shares at June 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 extends the term of the agreement until April 8, 2019 and amends each Right (which initially represented the right to purchase one share of the Common Stock) to represent the right to purchase, when exercisable, a unit consisting of one one-thousandth of a share (Unit) of Series A Junior Participating Preferred Stock, par value $0.01 per share (Series A Preferred Stock) at a purchase price of $150.00 per Unit (Purchase Price), subject to adjustment.

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

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

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 recognized the following amounts in employee stock-based compensation costs for the three and six months ended June 30, 2010 and 2009:

As of June 30, 2010, there was $30.1 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 2.5 years.

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

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

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(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 interest and other income (loss). The Other column includes items not related to the Company s reportable segments including real estate and corporate items.

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(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 $355.8 million and investments in cash equivalents, and assets for non-reportable segments.

(4)

Capital investments include reductions of $2.3 million and $31.8 million for the three-month periods ended June 30, 2010 and 2009, respectively, and an increase of $25.0 million and a reduction of $8.2 million for the six-month periods ended June 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 six months ended June 30, 2009 includes a $907.8 million non-cash ceiling test impairment of our 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 $335.1 million and $195.7 million for the three months ended June 30, 2010 and 2009, respectively, and $741.0 million and $391.7 million for the six months ended June 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)

<u>Three months ended June 30, 2010:</u>					
Operating revenues	$	$ 561,762	$ 74,701	$ (46,520)	$ 589,943
Operating costs and expenses:					
Gas purchases midstream services		142,269		(477)	141,792
Operating expenses		74,980	21,759	(45,796)	50,943
General and administrative expenses		32,104	4,776	(247)	36,633
Depreciation, depletion and amortization		136,640	7,366		144,006
Taxes, other than income taxes		8,858	1,394		10,252
Total operating costs and expenses		394,851	35,295	(46,520)	383,626
Operating income		166,911	39,406		206,317
Other income (loss)		(93)	9		(84)
Equity in earnings of subsidiaries	122,069			(122,069)	
Interest expense		936	5,244		6,180
Income (loss) before income taxes	122,069	165,882	34,171	(122,069)	200,053
Provision for income taxes		64,718	13,326		78,044
Net income (loss)	122,069	101,164	20,845	(122,069)	122,009
Less: Net loss attributable to noncontrolling interest		(60)			(60)
Net income (loss) attributable to Southwestern Energy	$ 122,069	$ 101,224	$ 20,845	$ (122,069)	$ 122,069

<u>Three months ended June 30, 2009:</u>

Operating revenues	$		$	460,436	$	49,263	$	(32,179)	$	477,520
Operating costs and expenses:										
Gas purchases midstream services				91,686				(499)		91,187
Operating expenses				46,836		15,238		(31,568)		30,506
General and administrative expenses				26,129		3,183		(112)		29,200
Depreciation, depletion and amortization				112,558		5,369				117,927
Taxes, other than income taxes				5,691		782				6,473
Total operating costs and expenses				282,900		24,572		(32,179)		275,293
Operating income				177,536		24,691				202,227
Other income				165		4				169
Equity in earnings of subsidiaries		121,100						(121,100)		
Interest expense				2,405		661				3,066
Income (loss) before income taxes		121,100		175,296		24,034		(121,100)		199,330
Provision for income taxes				69,152		9,120				78,272
Net income (loss)		121,100		106,144		14,914		(121,100)		121,058
Less: Net loss attributable to noncontrolling interest				(42)						(42)
Net income (loss) attributable to Southwestern Energy	$	121,100	$	106,186	$	14,914	$	(121,100)	$	121,100

24

25

26

Net cash provided by (used in) operating activities		
	$	(29,605)
	$	701,961

	$ 136,697
	$
	$ 809,053
Investing activities:	
Capital investments	
	(23,175)
	(814,494)
	(147,641)
	(985,310)
Proceeds from sale of property and equipment	

	347,150
	1,224
	348,374
Increase in restricted cash	
	(355,773)
	(355,773)
Other	
	6,364
	(13,016)
	4,207

	(2,445)
Net cash used in investing activities	
	(372,584)
	(480,360)
	(142,210)
	(995,154)
Financing activities:	
Intercompany activities	
	221,780

(227,355)

5,575

Payments on current portion of long-term debt

(600)

(600)

Payments on revolving long-term debt

(1,297,000)

	(1,297,000)
Borrowings under revolving long-term debt	
	1,478,100
	1,478,100
Other items	
	6,365
	6,365
Net cash provided by (used in) financing activities	
	408,645
	(227,355)

5,575

186,865

Increase (decrease) in cash and cash equivalents

6,456

(5,754)

62

764

Cash and cash equivalents at beginning of year

7,378

5,776

30

13,184

Cash and cash equivalents at end of period

$	13,834
$	22
$	92
$	
$	13,948

Six months ended June 30, 2009:

Net cash provided by operating activities

$	5,169
$	629,310
$	39,252
$	
$	673,731

Investing activities:

Capital investments	
	(4,851)
	(847,171)
	(111,954)
	(963,976)
Other	
	3,644
	(17,563)
	9,775

	(4,144)
Net cash used in investing activities	
	(1,207)
	(864,734)
	(102,179)
	(968,120)
Financing activities:	
Intercompany activities	
	(298,082)
	235,424

	62,658
Payments on current portion of long-term debt	(60,600)
	(60,600)
Payments on revolving long-term debt	(339,500)
	(339,500)
Borrowings under revolving long-term debt	

	535,500
	535,500
Other items	
	(35,043)
	(35,043)
Net cash provided by (used in) financing activities	
	(197,725)
	235,424
	62,658

		100,357
Decrease in cash and cash equivalents		(193,763)
		(269)
		(194,032)
Cash and cash equivalents at beginning of year		195,969
		308
		196,277
Cash and cash equivalents at end of period	$	2,206

$		
$	39	
$		
$	2,245	

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 six-month periods ended June 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 Oklahoma, Texas and Pennsylvania and in 2010 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 and 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 June 30, 2010 Compared with Three Months Ended June 30, 2009

We reported net income attributable to Southwestern Energy of $122.1 million for the three months ended June 30, 2010, or $0.35 per diluted share, compared to net income attributable to Southwestern Energy of $121.1 million, or $0.35 per diluted share, for the comparable period in 2009.

Our natural gas and oil production increased to 98.3 Bcfe for the three months ended June 30, 2010, up 32% from the three months ended June 30, 2009. The 24.0 Bcfe increase in our second quarter 2010 production was primarily due to a 23.0 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 15% to $4.27 per Mcf for the three months ended June 30, 2010 compared to the same period in 2009.

Operating income from our E&P segment was $162.5 million for the three months ended June 30, 2010 compared to operating income of $174.4 million for the same period in 2009. The decrease in operating income was the result of the revenue impact of our 32% growth in production which was more than offset by the 15% decline in our average realized gas prices and a $61.1 million increase in operating costs and expenses that resulted from our significant production growth.

Operating income for our Midstream Services segment was $43.8 million for the three months ended June 30, 2010, up from $27.8 million for the three months ended June 30, 2009, due to an increase of $25.5 million in gathering revenues and an increase of $2.9 million in the margin generated from our natural gas marketing activities, which were partially offset by a $12.3 million increase in operating costs and expenses, exclusive of gas purchase costs.

We had capital investments of $543.5 million for the three months ended June 30, 2010, of which $441.2 million was invested in our E&P segment, compared to $456.2 million for the same period of 2009, of which $402.1 million was invested in our E&P segment.

Six Months Ended June 30, 2010 Compared with Six Months Ended June 30, 2009

We reported net income attributable to Southwestern Energy of $293.9 million for the six months ended June 30, 2010, or $0.84 per diluted share, up from a net loss attributable to Southwestern Energy of $311.7 million, or $0.91 per diluted share, for the comparable period in 2009. The loss for the six months ended June 30, 2009 includes a $907.8 million, or $558.3 million net of taxes, non-cash ceiling test impairment of our natural gas and oil properties resulting from a significant decline in natural gas prices during the first quarter of 2009.

Our natural gas and oil production increased to 188.3 Bcfe for the six months ended June 30, 2010, up 36% from the six months ended June 30, 2009. The 50.1 Bcfe increase in 2010 production was primarily due to a 48.3 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 11% to $4.82 per Mcf for the six months ended June 30, 2010 compared to the same period in 2009.

Our E&P segment reported operating income of $412.9 million for the six months ended June 30, 2010, up from an operating loss of $553.5 million for the six months ended June 30, 2009. The loss for the six months ended June 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 six months of 2010 increased $58.6 million as a result of the revenue impact of our 36% increase in production which was partially offset by an 11% decline in our average realized gas prices and a $104.6 million increase in operating costs and expenses which resulted from our significant production growth.

Operating income for our Midstream Services segment was $81.4 million for the six months ended June 30, 2010, up from $55.2 million for the six months ended June 30, 2009, due to an increase of $49.7 million in gathering revenues and an increase of $1.2 million in the margin generated from our natural gas marketing activities, which were partially offset by a $24.6 million increase in operating costs and expenses, exclusive of gas purchase costs.

Net cash provided by operating activities increased 20% to $809.1 million for the six months ended June 30, 2010 compared to $673.7 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 in changes in working capital. We had capital investments of $1,017.2 million for the six months ended June 30, 2010, of which $852.7 million was invested in our E&P segment, compared to $959.4 million for the same period of 2009, of which $852.5 million was invested in our E&P segment.

Recent Development

Sale of Certain East Texas Properties

In the second quarter of 2010, we 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 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 at December 31, 2009. We retained the drilling and producing rights covering all other depths in the acreage, including our current James Lime and Pettet drilling programs. Under full cost accounting, this divestiture was accounted for as an adjustment of capitalized gas and oil properties with no gain recognized.

At closing, we 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. We will be subject to alternative minimum taxes totaling approximately $45 million in 2010 if no like-kind exchange transactions are effected pursuant to Section 1031 of the Internal Revenue Code.

We are keeping our production guidance unchanged for the third and fourth quarters of 2010, as our improving results in the Fayetteville Shale are currently expected to fully offset the expected production associated with the sold properties. Our capital investment program also remains unchanged at approximately $2.1 billion.

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.

Revenues

Revenues for our E&P segment were up $49.2 million, or 13%, for the three months ended June 30, 2010 compared to the same period in 2009. Higher natural gas production volumes in the second quarter of 2010 increased revenues by $119.7 million while lower realized prices for our gas production decreased revenue by $72.4 million compared to the second quarter of 2009. E&P revenues were up $163.2 million, or 22% for the six months ended June 30, 2010. Higher natural gas production volumes in the first six months of 2010 increased revenues by $271.3 million while lower realized prices for our gas production decreased revenue by $115.8 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 August 2, 2010, we had hedged 87.4 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 limit our exposure to price fluctuations. Additionally, as of August 2, 2010, our E&P segment has outstanding fair value hedges in place on 2.8 Bcf, 0.9 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 June 30, 2010 was up approximately 32%, from the comparable period in 2009, to 98.3 Bcfe, primarily due to a 23.0 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 June 30, 2010 and was up approximately 32% to 98.0 Bcf compared to the same period in 2009. Net production from the Fayetteville Shale was 83.6 Bcf for the three months ended June 30, 2010 compared to 60.6 Bcf for the same period in 2009. Natural gas and oil production for the six months ended June 30, 2010 was up approximately 36%, from the comparable period in 2009, to 188.3 Bcfe, primarily due to a 48.3 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 six months ended June 30, 2010 and was up approximately 36% to 187.7 Bcf compared to the same period in 2009. Net production from the Fayetteville Shale was 159.1 Bcf for the six months ended June 30, 2010 compared to 110.8 Bcf for the same period in 2009.

Commodity Prices

The average price realized for our gas production, including the effects of hedges, decreased approximately 15% to $4.27 per Mcf for the three months ended June 30, 2010, and decreased 11% to $4.82 per Mcf for the six months ended June 30, 2010, as compared to the same periods in 2009. The decrease in the average price realized for the three- and six-month periods ended June 30, 2010 as compared to the same periods in 2009 primarily reflects the decreased positive effect of our price hedging activities, which had a greater impact in 2009, despite the fact 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 $0.58 per Mcf for the three months ended June 30, 2010 compared to an increase of $2.11 per Mcf for the same period in 2009. Our hedging activities increased the average gas price $0.57 per Mcf for the six months ended June 30, 2010 compared to an increase of $2.12 per Mcf for the same period in 2009. We had protected approximately 54% of our gas production for the six months ended June 30, 2010 from the impact of widening basis differentials through financial hedging activities and physical sales arrangements. Disregarding the impact of hedges, the average price received for our gas production for the six months ended June 30, 2010 of $4.25 per Mcf was approximately $0.93 per Mcf higher than the six months ended June 30, 2009 and $0.45 lower than the average monthly NYMEX settlement price, primarily due to locational market differentials. At June 30, 2010, we had basis protected on approximately 99 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 2010, we expect to pay average third-party transportation charges in the range of $0.25 to $0.32 per Mcf and average fuel charges in the range of 0.25% to 1.00% of transported volumes.

As of June 30, 2010, we had NYMEX fixed price hedges in place on notional volumes of 73.3 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 14.0 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 June 30, 2010, we had NYMEX fixed price hedges in place on notional volumes of 30.1 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 22.1 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 $162.5 million for the three months ended June 30, 2010 compared to operating income of $174.4 million for the same period in 2009. The decrease in operating income was the result of the revenue impact of our 32% growth in production which was more than offset by the 15% decline in our average realized gas prices and a $61.1 million increase in operating costs and expenses that resulted from our significant production growth. Operating income from our E&P segment increased to $412.9 million for the six months ended June 30, 2010 compared to an operating loss of $553.5 million for the same period in 2009. The loss for the six months ended June 30, 2009 includes a $907.8 million non-cash ceiling test impairment of our natural gas and oil properties resulting 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 six months of 2010 increased $58.6 million as a result of the revenue impact of our 36% increase in production which was partially offset by an 11% decline in our average realized gas prices and a $104.6 million increase in operating costs and expenses which 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 June 30, 2010 compared to $0.73 for the same period in 2009. Lease operating expenses per Mcfe for our E&P segment were $0.81 for the six months ended June 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 six- month periods ended June 30, 2010, as compared to the same periods of 2009, are primarily due to increased gathering costs and increased costs associated with higher water disposal volumes related to our Fayetteville Shale operations.

General and administrative expenses per Mcfe decreased 9% to $0.31 for the three months ended June 30, 2010 and decreased 6% to $0.30 for the six months ended June 30, 2010, reflecting the effects of our increased production volumes. In total, general and administrative expenses for our E&P segment were $30.4 million for the three months ended June 30, 2010 compared to $25.0 million for the same period in 2009, and were $56.7 million for the six months ended June 30, 2010 compared to $44.7 million for the same period in 2009. Payroll, employee incentive compensation, and other employee-related costs associated with our E&P operations increased by $4.7 million for the three months ended June 30, 2010 and $9.0 million for the six months ended June 30, 2010 compared to the same periods in 2009 primarily as a result of the expansion of our E&P operations in the Fayetteville Shale play.

Taxes other than income taxes per Mcfe increased to $0.09 for the three months ended June 30, 2010 compared to $0.08 for the same period in 2009 and increased to $0.11 for six months ended June 30, 2010 compared to $0.10 for the same period 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 $1.33 per Mcfe for the three months ended June 30, 2010 compared to $1.46 per Mcfe for the same period in 2009. The decline in the average amortization rate for the three months ended June 30, 2010 compared to the same period of 2009 was primarily the result of lower finding and development costs. For the first six months of 2010, our full cost pool amortization rate averaged $1.37 per Mcfe compared to $1.63 per Mcfe for the same period in 2009. The decline in the average amortization rate for the six months ended June 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 finding 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 $674.6 million at June 30, 2010 compared to $595.4 million at December 31, 2009. The increase in unevaluated costs since December 31, 2009 primarily resulted from a $31.2 million increase in our drilling activity, a $30.4 million increase in our undeveloped leasehold acreage and seismic costs and a $7.3 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.

Revenues

Revenues from our marketing activities were up 68% to $484.7 million for the three months ended June 30, 2010 and were up 64% to $1,049.7 million for the six months ended June 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 June 30, 2010, volumes marketed increased 33% and the price received for volumes marketed increased 26% compared to the same period in 2009. For the six months ended June 30, 2010, volumes marketed increased 29% and the price received for volumes marketed increased 27% 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 E&P operated wells accounted for 96% and 91% of the marketed volumes for the three months ended June 30, 2010 and 2009, respectively. For the six months ended June 30, 2010 and 2009, production from our E&P operated wells accounted for 97% and 93% of the marketed volumes, respectively.

Revenues from our gathering activities were up 52% to $74.2 million for the three months ended June 30, 2010 and up 55% to $140.8 million for the six months ended June 30, 2010 compared to the respective periods in 2009. The increases in gathering revenues resulted from a 48% increase in gas volumes gathered for the three months ended June 30, 2010 and a 52% increase in gas volumes gathered for the six months ended June 30, 2010 compared to the respective periods in 2009. Substantially all of the increases in gathering revenues for the three months ended June 30, 2010 and six months ended June 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.

Operating Income

Operating income from our Midstream Services segment increased to $43.8 million for the three months ended June 30, 2010 compared to $27.8 million for the same period in 2009 and increased to $81.4 million for the six months ended June 30, 2010 compared to $55.2 million for the same period in 2009. The increases in operating income reflect the substantial increases in gas volumes marketed and gathered which primarily resulted from our increased E&P production volumes. The $16.0 million increase in operating income for the three months ended June 30, 2010 was primarily due to a $25.5 million increase in gathering revenues which was partially offset by an increase in operating costs and expenses of $12.3 million. The $26.2 million increase in operating income for six months ended June 30, 2010 was primarily due to a $49.7 million increase in gathering revenues which was partially offset by an increase in operating costs and expenses of $24.6 million. The remaining changes in operating income were due to changes in the margin generated by our gas marketing activities. Marketing margin increased $2.9 million for the three months ended June 30, 2010 and increased $1.2 million for the six months ended June 30, 2010 compared to the respective periods of 2009. Margins 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 and Interest Income

Interest expense, net of capitalization, increased to $6.2 million for the three months ended June 30, 2010 compared to $3.1 million for the same period in 2009 and increased to $12.7 million for the six months ended June 30, 2010 compared to $6.8 million for the same period in 2009. The increases in interest expense, net of capitalization, for the three- and six- month periods ended June 30, 2010 were primarily due to decreases in capitalized interest of $3.0 million and $6.3 million, respectively, which resulted from our lower weighted average interest rate for the three- and six-month periods ended June 30, 2010 compared to the same periods in 2009. We capitalized interest of $8.5 million and $16.4 million for the three- and six-month periods ended June 30, 2010, respectively, compared to $11.5 million and $22.7 million for the same periods in 2009.

Interest income was less than $0.1 million for both of the three-month periods ended June 30, 2010 and 2009. Interest income was $0.1 million for the six-month period ended June 30, 2010 compared to $0.4 million for the same period in 2009. Interest income is recorded in other income in the unaudited condensed consolidated statements of operations.

Income Taxes

Our effective tax rates were 39.0% and 38.2% for the six months ended June 30, 2010 and 2009, respectively. For the six months ended June 30, 2010, we recorded an income tax expense of $187.9 million compared to an income tax benefit of $192.7 million for the same period in 2009. The income tax benefit for the six months ended June 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. We will be subject to alternative minimum taxes totaling approximately $45 million in 2010 if no like-kind exchange transactions are effected pursuant to Section 1031 of the Internal Revenue Code. Except for this potential tax liability related to alternative minimum taxes, we do not expect to be subject to current federal income taxes in 2010.

Stock-Based Compensation Costs

We expensed $2.1 million and capitalized $1.7 million for stock-based compensation costs recognized during the three-month period ended June 30, 2010 compared to $2.3 million expensed and $1.4 million capitalized for the comparable period in 2009. We expensed $4.4 million and capitalized $3.4 million for stock-based compensation costs recognized during the six-month period ended June 30, 2010 compared to $4.5 million expensed and $2.9 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) and funds accessed through debt and equity markets 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. As of June 30, 2010, we had borrowings of $505.6 million under our Credit Facility compared to $324.5 million at December 31, 2009.

Net cash provided by operating activities increased 20% to $809.1 million for the six months ended June 30, 2010 compared to $673.7 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 in changes in working capital. For the six months ended June 30, 2010, cash generated from our operating activities funded 82% 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 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 $1,017.2 million for the six months ended June 30, 2010 compared to $959.4 million for the same period in 2009. Our E&P segment investments were $852.7 million for the six months ended June 30, 2010 compared to $852.5 million for the same period in 2009. Our E&P segment capitalized internal costs of $67.0 million for the six months ended June 30, 2010 compared to $49.8 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.

Financing Requirements

Our total debt outstanding was $1,179.2 million at June 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 June 30, 2010, we had $505.6 million outstanding under our Credit Facility with a weighted average interest rate of 1.222% 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 87.5 basis points over LIBOR. In July 2010, Standard and Poor s upgraded our corporate credit rating to BBB- from BB+. We currently have a Corporate Family Rating of Ba2 by Moody s. Any downgrades in our public debt ratings could increase our cost of funds under the Credit Facility.

Our Credit Facility contains covenants which impose certain restrictions on us. Under the Credit Facility, 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 June 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 June 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 June 30, 2010, our capital structure consisted of 31% debt and 69% equity. Equity at June 30, 2010 includes a gain in accumulated other comprehensive gain of $117.2 million related to our hedging activities and a loss of $10.7 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 June 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 August 2, 2010 we have hedged 87.4 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 August 2, 2010, our E&P and Midstream Services segments have outstanding fair value hedges in place on 3.0 Bcf, 1.0 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 June 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 June 30, 2010, we have contributed $3.6 million to our pension plans and less than $0.1 million to our postretirement benefit plan. At June 30, 2010, we recognized a liability of $13.8 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 $247.0 million at June 30, 2010 compared to positive working capital of $28.1 million at December 31, 2009. Current assets increased by $346.8 million at June 30, 2010 compared to December 31, 2009, primarily due to a $355.8 million increase in restricted cash related to the sale of certain oil and gas leases, wells and gathering equipment held by us 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. Current liabilities increased by $127.9 million at June 30, 2010 compared to December 31, 2009 primarily as a result of a $57.3 million increase in our current deferred income taxes related to our hedging activities, a $40.6 million increase in accounts payable and a $27.4 million increase in advances from partners.

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. No single customer accounted for greater than 13% of accounts receivable at June 30, 2010. In addition, see the discussion of credit risk associated with commodities trading below.

Interest Rate Risk

At June 30, 2010, we had $1,179.2 million of total debt with a weighted average interest rate of 4.79%. Our revolving credit facility has a floating interest rate (1.222% at June 30, 2010). At June 30, 2010, we had $505.6 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 June 30, 2010, the fair value of our financial instruments related to natural gas production and gas-in-storage was a $191.9 million asset.

(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 $4,000.

(2)

Includes fixed-price swaps for 0.1 Bcf relating to future sales from our underground storage facility that have a fair value liability of approximately $13,000.

At June 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 six months ended June 30, 2010, we recorded an unrealized gain of $7.9 million related to the basis swaps that did not qualify for hedge accounting treatment and an unrealized loss of $5.1 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 June 30, 2010, our Midstream Services segment had outstanding fair value hedges in place on 0.2 Bcf, 0.1 Bcf, 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 July 2010 through March 2012 and have a net fair value liability of $0.2 million as of June 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 June 30, 2010. There were no changes in our internal control over financial reporting during the three months ended June 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.

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

ITEM 1A. RISK FACTORS.

There were no additions or material changes to the Company s risk factors as disclosed in Item 1A of Part I in the Company s 2009 Annual Report on Form 10-K.

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

Not applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES.

Not applicable.

ITEM 5. OTHER INFORMATION.

Not applicable.

ITEM 6. EXHIBITS.

(3.1)

Amended and Restated Certificate of Incorporation of Southwestern Energy Company (Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed May 24, 2010).

(3.2)

Amended and Restated Bylaws of Southwestern Energy Company. Effective as of May 18, 2010 (Incorporated by reference to Exhibit 3.2 to the Registrant's Current Report on Form 8-K filed May 24, 2010).

(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.