UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

(Mark One)
[X] Quarterly Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended **June 30, 2011**

Or

[ ] Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from __________ to __________

Commission file number: **1-08246**

Southwestern Energy Company

(Exact name of registrant as specified in its charter)

Delaware	**71-0205415**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
2350 North Sam Houston Parkway East, Suite 125, Houston, Texas	**77032**
(Address of principal executive offices)	(Zip Code)

(281) 618-4700
(Registrant’s telephone number, including area code)

Not Applicable
(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes☒ No☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer”, “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

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

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

Class	Outstanding as of July 26, 2011
Common Stock, Par Value $0.01	347,991,470

SOUTHWESTERN ENERGY COMPANY

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FOR THE QUARTERLY PERIOD ENDED June 30, 2011

PART I – FINANCIAL INFORMATION

PART II – OTHER INFORMATION

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

All statements, other than historical fact or present financial information, may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements that address activities, outcomes and other matters that should or may occur in the future, including, without limitation, statements regarding the financial position, business strategy, production and reserve growth and other plans and objectives for our future operations, are forward-looking statements. Although we believe the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance. We have no obligation and make no undertaking to publicly update or revise any forward-looking statements, except as may be required by law.

Forward-looking statements include the items identified in the preceding paragraph, information concerning possible or assumed future results of operations and other statements in this Form 10-Q identified by words such as "anticipate," "project," "intend," "estimate," "expect," "believe," "predict," "budget," "projection," "goal," "plan," "forecast," "target" or similar expressions.

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

- the timing and extent of changes in market conditions and prices for natural gas and oil (including regional basis differentials);
- our ability to fund our planned capital investments;
- our ability to transport our production to the most favorable markets or at all;
- the timing and extent of our success in discovering, developing, producing and estimating reserves;
- the economic viability of, and our success in drilling, our large acreage position in the Fayetteville Shale play overall as well as relative to other productive shale gas plays;
- the impact of government regulation, including any increase in severance or similar taxes, legislation relating to hydraulic fracturing, the climate and over-the-counter derivatives;
- the costs and availability of oilfield personnel, services and drilling supplies, raw materials, and equipment, including pressure pumping equipment and crews;

- our ability to determine the most effective and economic fracture stimulation for the Fayetteville Shale formation;
- our future property acquisition or divestiture activities;
- the impact of the adverse outcome of any material litigation against us;
- the effects of weather;
- increased competition and regulation;
- the financial impact of accounting regulations and critical accounting policies;
- the comparative cost of alternative fuels;
- conditions in capital markets, changes in interest rates and the ability of our lenders to provide us with funds as agreed;
- credit risk relating to the risk of loss as a result of non-performance by our counterparties; and
- any other factors listed in the reports we have filed and may file with the Securities and Exchange Commission ("SEC").

We caution you that the forward-looking statements contained in this Form 10-Q are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of natural gas and oil. These risks include, but are not limited to, commodity price volatility, third-party interruption of sales to market, inflation, the risk of failure of exploration programs in areas in which oil or natural gas has not previously been discovered or produced, lack of availability of goods and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating proved natural gas and oil reserves and in projecting future rates of production and timing of development expenditures and the other risks described in our Annual Report on Form 10-K for the year ended December 31, 2010 (the "2010 Annual Report on Form 10-K"), and all quarterly reports on Form 10-Q filed subsequently thereto, including this Form 10-Q ("Form 10-Qs").

Should one or more of the risks or uncertainties described above or elsewhere in this Form 10-Q occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages.

All forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement.

PART I – FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	For the three months ended June 30, 2011	For the three months ended June 30, 2010	For the six months ended June 30, 2011	For the six months ended June 30, 2010
	(in thousands, except share/per share amounts)			
Operating Revenues:				
Gas sales	$ 524,466	$ 415,576	$ 991,910	$ 894,987
Gas marketing	201,358	142,579	372,456	300,252
Oil sales	2,503	3,620	5,230	7,082
Gas gathering	36,839	28,215	71,420	53,588
Other	—	(47)	485	2,151
	765,166	589,943	1,441,501	1,258,060
Operating Costs and Expenses:				
Gas purchases – midstream services	200,052	141,792	370,282	299,460
Operating expenses	55,054	50,943	111,852	87,509
General and administrative expenses	40,238	36,633	77,355	69,577
Depreciation, depletion and amortization	171,620	144,006	335,067	283,023
Taxes, other than income taxes	15,660	10,252	31,752	24,084
	482,624	383,626	926,308	763,653
Operating Income	282,542	206,317	515,193	494,407
Interest Expense:				
Interest on debt	16,640	14,199	31,684	28,128
Other interest charges	1,001	505	2,512	944
Interest capitalized	(11,471)	(8,524)	(20,590)	(16,384)
	6,170	6,180	13,606	12,688
Other Income (Loss), Net	69	(84)	443	(61)
Income Before Income Taxes	276,441	200,053	502,030	481,658
Provision for Income Taxes:				
Current	100	2,700	200	2,700
Deferred	108,887	75,344	197,767	185,181
	108,987	78,044	197,967	187,881
Net income	167,454	122,009	304,063	293,777
Less: Net loss attributable to noncontrolling interest	—	(60)	—	(89)
Net Income Attributable to Southwestern Energy	$ 167,454	$ 122,069	$ 304,063	$ 293,866
Earnings Per Share:				
Net income attributable to Southwestern Energy stockholders – Basic	$ 0.48	$ 0.35	$ 0.88	$ 0.85
Net income attributable to Southwestern Energy stockholders – Diluted	$ 0.48	$ 0.35	$ 0.87	$ 0.84
Weighted Average Common Shares Outstanding:				
Basic	347,132,830	345,288,773	346,984,194	345,194,534
Diluted	349,970,819	349,341,731	349,840,044	349,364,654

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

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

	June 30, 2011	December 31, 2010
ASSETS	(in thousands)	
Current Assets:		
Cash and cash equivalents	$ 13,279	$ 16,055
Restricted cash	85,002	—
Accounts receivable	336,717	351,573
Inventories	33,378	35,098
Hedging asset	183,278	130,412
Other	34,488	47,755
Total Current Assets	686,142	580,893
Property and Equipment:		
Gas and oil properties, using the full cost method, including $806.4 million in 2011 and $712.1 million in 2010 excluded from amortization	8,570,320	7,749,863
Gathering systems	923,123	817,465
Other	480,381	413,557
Total property and equipment	9,973,824	8,980,885
Less: Accumulated depreciation, depletion and amortization	4,042,758	3,682,688
	5,931,066	5,298,197
Other Assets	124,893	138,373
TOTAL ASSETS	$ 6,742,101	$ 6,017,463
LIABILITIES AND EQUITY		
Current Liabilities:		
Current portion of long-term debt	$ 1,200	$ 1,200
Accounts payable	536,213	473,890
Taxes payable	37,711	50,051
Interest payable	19,790	19,954
Advances from partners	89,654	81,705
Hedging liability	4,880	7,685
Current deferred income taxes	63,547	44,089
Other	14,354	15,409
Total Current Liabilities	767,349	693,983
Long-Term Debt	1,215,400	1,093,000
Other Liabilities:		
Deferred income taxes	1,323,970	1,130,292
Long-term hedging liability	32,816	40,188
Pension and other postretirement liabilities	14,982	15,777
Other long-term liabilities	81,153	79,347
	1,452,921	1,265,604
Commitments and Contingencies		
Equity:		
Southwestern Energy stockholders' equity		
Common stock, $0.01 par value; authorized 1,250,000,000 shares; issued 348,108,100 shares in 2011 and 347,733,839 in 2010	3,481	3,477
Additional paid-in capital	874,827	862,423
Retained earnings	2,322,508	2,018,445
Accumulated other comprehensive income	108,383	83,975
Common stock in treasury, 125,550 shares in 2011 and 156,636 in 2010	(2,768)	(3,444)
Total Equity	3,306,431	2,964,876
TOTAL LIABILITIES AND EQUITY	$ 6,742,101	$ 6,017,463

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

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

	For the six months ended June 30, 2011	2010
	(in thousands)	
Cash Flows From Operating Activities		
Net income	$ 304,063	$ 293,777
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	337,035	283,828
Deferred income taxes	197,767	185,181
Unrealized gain on derivatives	(3,975)	(2,275)
Stock-based compensation	4,686	4,433
Other	170	(1,449)
Change in assets and liabilities:		
Accounts receivable	14,856	(31,156)
Inventories	6,761	14,833
Accounts payable	(7,380)	8,927
Taxes payable	(12,340)	4,213
Interest payable	(164)	178
Advances from partners	7,949	27,431
Other assets and liabilities	7,502	21,132
Net cash provided by operating activities	856,930	809,053
Cash Flows From Investing Activities		
Capital investments	(1,024,658)	(985,310)
Proceeds from sale of property and equipment	121,133	348,374
Transfers to restricted cash	(85,002)	(355,773)
Other	3,879	(2,445)
Net cash used in investing activities	(984,648)	(995,154)
Cash Flows From Financing Activities		
Payments on current portion of long-term debt	(600)	(600)
Payments on revolving long-term debt	(1,717,600)	(1,297,000)
Borrowings under revolving long-term debt	1,840,600	1,478,100
Change in bank drafts outstanding	9,260	5,059
Revolving credit facility costs	(10,210)	—
Proceeds from exercise of common stock options	3,365	1,306
Net cash provided by financing activities	124,815	186,865
Effect of exchange rate changes on cash	127	—
Increase (decrease) in cash and cash equivalents	(2,776)	764
Cash and cash equivalents at beginning of year	16,055	13,184
Cash and cash equivalents at end of period	$ 13,279	$ 13,948

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

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

	Common Stock		Additional		Accumulated Other	Common	
	Shares Issued	Amount	Paid-In Capital	Retained Earnings	Comprehensive Income	Stock in Treasury	Total
	(in thousands)						
Balance at December 31, 2010	347,734	$ 3,477	$ 862,423	$ 2,018,445	$ 83,975	$ (3,444)	$ 2,964,876
Comprehensive income:							
Net income	—	—	—	304,063	—	—	304,063
Change in derivatives	—	—	—	—	23,627	—	23,627
Change in pension and other postretirement liabilities	—	—	—	—	393	—	393
Currency translation adjustment	—	—	—	—	388	—	388
Total comprehensive income							328,471
Stock-based compensation	—	—	8,501	—	—	—	8,501
Exercise of stock options	398	4	3,361	—	—	—	3,365
Issuance of restricted stock	6	—	—	—	—	—	—
Cancellation of restricted stock	(30)	—	—	—	—	—	—
Treasury stock – non-qualified plan	—	—	542	—	—	676	1,218
Balance at June 30, 2011	348,108	$ 3,481	$ 874,827	$ 2,322,508	$ 108,383	$ (2,768)	$ 3,306,431

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

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

	For the three months ended June 30,		For the six months ended June 30,	
	2011	2010	2011	2010
	(in thousands)			
Net income	$ 167,454	$ 122,009	$ 304,063	$ 293,777
Change in derivatives:				
Reclassification to earnings [(1)]	(32,756)	(38,241)	(64,414)	(67,542)
Ineffectiveness [(2)]	(1,209)	3,162	(1,267)	3,105
Change in fair value of derivative instruments [(3)]	82,584	21,616	89,308	86,285
Total change in derivatives	48,619	(13,463)	23,627	21,848
Change in pension and other postretirement liabilities [(4)]	196	191	393	382
Change in currency translation adjustment	126	—	388	—
Comprehensive income	216,395	108,737	328,471	316,007
Less: Comprehensive loss attributable to the noncontrolling interest	—	(60)	—	(89)
Comprehensive income attributable to Southwestern Energy	$ 216,395	$ 108,797	$ 328,471	$ 316,096

(1) Net of ($20.9), ($24.5), ($41.2) and ($45.3) million in taxes for the three months ended June 30, 2011 and 2010, and the six months ended June 30, 2011 and 2010, respectively.

(2) Net of ($0.8), $2.0, ($0.8) and $2.0 million in taxes for the three months ended June 30, 2011 and 2010, and the six months ended June 30, 2011 and 2010, respectively.

(3) Net of $52.8, $13.8, $57.1 and $59.8 million in taxes for the three months ended June 30, 2011 and 2010, and the six months ended June 30, 2011 and 2010, respectively.

(4) Net of $0.1, $0.1, $0.2 and $0.2 million in taxes for the three months ended June 30, 2011 and 2010, and the six months ended June 30, 2011 and 2010, respectively.

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

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

(1) BASIS OF PRESENTATION AND NEW ACCOUNTING STANDARDS

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

The accompanying unaudited condensed consolidated financial statements were prepared using accounting principles generally accepted in the United States of America ("GAAP") for interim financial information and in accordance with the rules and regulations of the 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, 2010 ("2010 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 2010 Annual Report on Form 10-K. The Company evaluates subsequent events through the date the financial statements are issued.

On January 1, 2011, 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 entities to provide a reconciliation of purchases, sales, issuance and settlements of anything valued with a Level 3 method, which is used to price the hardest to value instruments. The implementation did not have an impact on the Company's results of operations, financial position or cash flows.

(2) DIVESTITURE

In the second quarter of 2011, the Company sold certain oil and gas leases, wells and gathering equipment in Shelby, San Augustine, and Sabine Counties in East Texas for approximately $108.1 million, before customary purchase price adjustments. This divestiture included only the Haynesville and Middle Bossier Shale intervals in the affected acreage, which intervals had net production of approximately 7.0 MMcf per day as of May 25, 2011 and proved net reserves of approximately 25.1 Bcf at December 31, 2010. 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 $85 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 November 2011.

(3) PREPAID EXPENSES

The components of prepaid expenses included in other current assets as of June 30, 2011 and December 31, 2010 consisted of the following:

	June 30, 2011	December 31, 2010
	(in thousands)	
Prepaid drilling costs	$ 20,706	$ 21,997
Prepaid insurance	3,089	7,690
Total	$ 23,795	$ 29,687

(4) INVENTORY

Inventory recorded in current assets includes $8.9 million at June 30, 2011 and $10.0 million at December 31, 2010, for natural gas in underground storage owned by the Company's E&P segment, and $24.4 million at June 30, 2011 and $25.1 million at December 31, 2010, 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. 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 $18.1 million at June 30, 2011 and $20.6 million at December 31, 2010 for inventory held by the Midstream Services segment consisting primarily of pipe that will be used to construct gathering systems for the Fayetteville Shale and Marcellus Shale plays.

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) NATURAL 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 on a country by country basis and amortized over the estimated lives of the properties using the units-of-production method. These capitalized costs, less accumulated amortization and related deferred income taxes, are subject to a ceiling test that limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved natural gas and oil reserves discounted at 10 percent plus the lower of cost or market value of unproved properties. Any costs in excess of the ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, even though higher natural gas and oil prices may subsequently increase the ceiling. The average quoted price from the first day of each month from the previous 12 months, including the impact of derivatives qualifying as cash flow hedges, is used to calculate the ceiling value of reserves.

Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $4.21 per MMBtu and $86.60 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 its United States natural gas and oil properties did not exceed the ceiling amount and did not result in a ceiling test impairment at June 30, 2011. Cash flow hedges of gas production in place increased the ceiling value by approximately $324.2 million at June 30, 2011. 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.

All of our costs directly associated with the acquisition and evaluation of properties in New Brunswick, Canada relating to our exploration program at June 30, 2011 were unproved and did not exceed the ceiling amount. If our exploration program in Canada is unsuccessful on all or a portion of these properties, a ceiling test impairment may result in the future.

(6) EARNINGS PER SHARE

The following table presents the computation of earnings per share for the three- and six-month periods ended June 30, 2011 and 2010:

	For the three months ended June 30,		For the six months ended June 30,	
	2011	2010	2011	2010
Net income attributable to Southwestern Energy (in thousands)	$ 167,454	$ 122,069	$ 304,063	$ 293,866
Number of common shares:				
Weighted average outstanding	347,132,830	345,288,773	346,984,194	345,194,534
Issued upon assumed exercise of outstanding stock options	2,583,711	3,812,833	2,643,537	3,911,348
Effect of issuance of nonvested restricted common stock	254,278	240,125	212,313	258,772
Weighted average and potential dilutive outstanding(1)	349,970,819	349,341,731	349,840,044	349,364,654
Earnings per share:				
Net income attributable to Southwestern Energy stockholders - basic	$ 0.48	$ 0.35	$ 0.88	$ 0.85
Net income attributable to Southwestern Energy stockholders - diluted	$ 0.48	$ 0.35	$ 0.87	$ 0.84

(1) Options for 749,910 shares and 3,421 shares of restricted stock were excluded from the calculation for the three months ended June 30, 2011 because they would have had an antidilutive effect. 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 813,878 shares and 3,041 shares of restricted stock were excluded from the calculation for the six months ended June 30, 2011 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.

(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, 2011 and December 31, 2010, 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, 2011 and December 31, 2010:

	Derivative Assets			
	June 30, 2011		December 31, 2010	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Derivatives designated as hedging instruments:				
Fixed and floating price swaps	Hedging asset	$ 123,608	Hedging asset	$ 81,797
Costless-collars	Hedging asset	59,532	Hedging asset	48,582
Fixed and floating price swaps	Other assets	19,717	Other assets	5,086
Costless-collars	Other assets	37,665	Other assets	72,827
Total derivatives designated as hedging instruments		$ 240,522		$ 208,292
Derivatives not designated as hedging instruments:				
Basis swaps	Hedging asset	$ 138	Hedging asset	$ 33
Basis swaps	Other assets	196	Other assets	—
Total derivatives not designated as hedging instruments		$ 334		$ 33
Total derivative assets		$ 240,856		$ 208,325

	Derivative Liabilities			
	June 30, 2011		December 31, 2010	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Derivatives designated as hedging instruments:				
Fixed and floating price swaps	Hedging liability	$ 2,266	Hedging liability	$ 1,774
Costless-collars	Hedging liability	2,374	Hedging liability	3,903
Fixed and floating price swaps	Long-term hedging liability	27,294	Long-term hedging liability	22,334
Costless-collars	Long-term hedging liability	5,262	Long-term hedging liability	17,854
Total derivatives designated as hedging instruments		$ 37,196		$ 45,865
Derivatives not designated as hedging instruments:				
Basis swaps	Hedging liability	$ 240	Hedging liability	$ 2,008
Basis swaps	Long-term hedging liability	260	Long-term hedging liability	—
Total derivatives not designated as hedging instruments		$ 500		$ 2,008
Total derivative liabilities		$ 37,696		$ 47,873

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, 2011, the Company had cash flow hedges on the following volumes of natural gas production (in Bcf):

Year:	Fixed price swaps	Costless-collars
2011	128.9	31.3
2012	185.7	80.5
2013	185.2	—

As of June 30, 2011, the Company recorded a net gain in accumulated other comprehensive income related to its hedging activities of $120.1 million. This amount is net of a deferred income tax liability recorded as of June 30, 2011 of $76.8 million. The amount recorded in accumulated other comprehensive income will be relieved over time and recognized in the statement of operations as the physical transactions being hedged occur. Assuming the market prices of natural gas futures as of June 30, 2011 remain unchanged, the Company would expect to transfer an aggregate after-tax net gain of approximately $104.7 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 $105.6 million for the six-month period ended June 30, 2011 compared to a realized gain of $112.8 million during the six-month period ended June 30, 2010. Volatility in earnings and other comprehensive income may occur in the future as a result 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, 2011 and 2010.

	Gain Recognized in Other Comprehensive Income (Effective Portion)			
	For the three months ended June 30,		For the six months ended June 30,	
Derivative Instrument	2011	2010	2011	2010
	(in thousands)			
Fixed price swaps	$ 120,510	$ 15,220	$ 129,579	$ 90,534
Costless-collars	$ 14,875	$ 20,215	$ 16,829	$ 55,532

	Classification of Gain Reclassified from Accumulated Other Comprehensive Income into Earnings (Effective Portion)	Gain Reclassified from Accumulated Other Comprehensive Income into Earnings (Effective Portion)			
		For the three months ended June 30,		For the six months ended June 30,	
Derivative Instrument		2011	2010	2011	2010
		(in thousands)			
Fixed price swaps	Gas Sales	$ 41,736	$ 44,581	$ 78,537	$ 78,254
Costless-collars	Gas Sales	$ 11,962	$ 18,109	$ 27,060	$ 34,562

	Classification of Gain (Loss) Recognized in Earnings (Ineffective Portion)	Gain (Loss) Recognized in Earnings (Ineffective Portion)			
		For the three months ended June 30,		For the six months ended June 30,	
Derivative Instrument		2011	2010	2011	2010
		(in thousands)			
Fixed price swaps	Gas Sales	$ 3,066	$ (4,139)	$ 999	$ (3,666)
Costless-collars	Gas Sales	$ (1,083)	$ (1,045)	$ 1,078	$ (1,420)

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, 2011 and December 31, 2010, 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, as applicable, 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, 2011, the Company had basis swaps on natural gas production that did not qualify for hedge accounting treatment of 16.6 Bcf, 26.7 Bcf and 19.1 Bcf for 2011, 2012 and 2013, respectively.

The following table summarizes 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, 2011 and 2010.

		Unrealized Gain (Loss) Recognized in Earnings			
	Income Statement Classification	For the three months ended June 30,		For the six months ended June 30,	
Derivative Instrument	of Unrealized Gain (Loss)	2011	2010	2011	2010
		(in thousands)			
Basis swaps	Gas Sales	$ 902	$ 3,066	$ 1,808	$ 7,876

		Realized Gain (Loss) Recognized in Earnings			
	Income Statement Classification	For the three months ended June 30,		For the six months ended June 30,	
Derivative Instrument	of Realized Gain (Loss)	2011	2010	2011	2010
		(in thousands)			
Basis swaps	Gas Sales	$ (99)	$ (2,387)	$ (2,355)	$ (7,231)

(8) FAIR VALUE MEASUREMENTS

The carrying amounts and estimated fair values of the Company's financial instruments as of June 30, 2011 and December 31, 2010 were as follows:

	June 30, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Cash and cash equivalents	$ 13,279	$ 13,279	$ 16,055	$ 16,055
Restricted cash	$ 85,002	$ 85,002	$ —	$ —
Unsecured revolving credit facility	$ 544,200	$ 544,200	$ 421,200	$ 421,200
Senior notes	$ 672,400	$ 770,435	$ 673,000	$ 761,372
Derivative instruments	$ 203,160	$ 203,160	$ 160,452	$ 160,452

The carrying values of cash and cash equivalents, restricted cash, accounts receivable, accounts payable, other current assets and current liabilities on the 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 senior notes 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 4.8% at June 30, 2011 and 5.2% at December 31, 2010. The carrying values of the borrowings under the Company's unsecured revolving credit facility at June 30, 2011 and December 31, 2010 approximate fair value.

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

GAAP establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. As presented in the tables below, this hierarchy consists of three broad levels:

Level 1 valuations - Consist of unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority.

Level 2 valuations - Consist of quoted market information for the calculation of fair market value.

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

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

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

	June 30, 2011			
	Fair Value Measurements Using:			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Assets (Liabilities) at Fair Value
Derivative assets	$ —	$ 143,325	$ 97,531	$ 240,856
Derivative liabilities	—	(29,560)	(8,136)	(37,696)
Total	$ —	$ 113,765	$ 89,395	$ 203,160

	December 31, 2010			
	Fair Value Measurements Using:			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Assets (Liabilities) at Fair Value
Derivative assets	$ —	$ 86,883	$ 121,442	$ 208,325
Derivative liabilities	—	(24,108)	(23,765)	(47,873)
Total	$ —	$ 62,775	$ 97,677	$ 160,452

The table below presents reconciliations for the change in net fair value of derivative 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, 2011. The fair values of Level 3 derivative instruments are estimated using proprietary valuation models that utilize both market observable and unobservable parameters. Level 3 instruments presented in the table consist of net derivatives valued using pricing models incorporating assumptions that, in the Company's judgment, reflect the assumptions a marketplace participant would have used at June 30, 2011.

	For the three months ended June 30,		For the six months ended June 30,	
	2011	2010	2011	2010
	(in thousands)			
Balance at beginning of period	$ 85,580	$ 48,394	$ 97,677	$ 24,720
Total gains or losses (realized/unrealized):				
Included in earnings	11,682	17,743	27,592	33,787
Included in other comprehensive income	3,996	3,151	(11,310)	22,390
Purchases, issuances, and settlements:				
Purchases	—	—	—	—
Issuances	—	—	—	—
Settlements	(11,863)	(15,722)	(24,706)	(27,331)
Transfers into/out of Level 3	—	—	142	—
Balance at end of period	$ 89,395	$ 53,566	$ 89,395	$ 53,566
Change in unrealized gains included in earnings relating to derivatives still held as of June 30	$ (181)	$ 2,021	$ 2,886	$ 6,456

(9) DEBT

The components of debt as of June 30, 2011 and December 31, 2010 consisted of the following:

	June 30, 2011	December 31, 2010
	(in thousands)	
Short-term debt:		
7.15% Senior Notes due 2018	$ 1,200	$ 1,200
Total short-term debt	1,200	1,200
Long-term debt:		
Variable rate (2.165% at June 30, 2011 and 0.887% at December 31, 2010) unsecured revolving credit facility, expires February 2016	544,200	421,200
7.5% Senior Notes due 2018	600,000	600,000
7.35% Senior Notes due 2017	15,000	15,000
7.125% Senior Notes due 2017	25,000	25,000
7.15% Senior Notes due 2018	31,200	31,800
Total long-term debt	1,215,400	1,093,000
Total debt	$ 1,216,600	$ 1,094,200

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 currently 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. Please refer to Note 16, "Condensed Consolidating Financial Information" for additional information.

Credit Facility

In February 2011, the Company amended and restated its unsecured revolving credit facility, increasing the borrowing capacity to $1.5 billion and extending the maturity date to February 2016 ("Credit Facility"). The amount available under the Credit Facility may be increased to $2.0 billion at any time upon the Company's agreement with its existing or additional lenders. The interest rate on the amended credit facility is calculated based upon our debt rating and is currently 200 basis points over the current London Interbank Offered Rate (LIBOR) and was 200 basis points over LIBOR at June 30, 2011. The Credit Facility is guaranteed by the Company's subsidiary, SEECO. The Credit Facility requires additional subsidiary guarantors if certain guaranty coverage levels are not satisfied. The revolving credit facility contains covenants which impose certain restrictions on the Company. Under the credit agreement, the Company may not issue total debt in excess of 60% of its total capital and must maintain a ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) to interest expense of 3.5 or above. The terms of the Credit Facility also include covenants that restrict the ability of the Company and its material subsidiaries to merge, consolidate or sell all or substantially all of their assets, restrict the ability of the Company and its subsidiaries to incur liens and restrict the ability of the Company's subsidiaries to incur indebtedness. At June 30, 2011, the Company's capital structure consisted of 27% debt and 73% equity and it was in compliance with the covenants of its debt agreements. While the Company believes all of the lenders under the Credit Facility have the ability to provide funds, it cannot predict whether each will be able to meet its obligation under the facility.

(10) COMMITMENTS AND CONTINGENCIES

Commitments

During the first and second quarters of 2011, the Company's marketing subsidiary, Southwestern Energy Services Company ("SES"), entered into a number of short and long term firm transportation service and gathering agreements in support of the Company's growing Marcellus Shale operations in Pennsylvania and the Company has provided certain guarantees of a portion of SES's obligations under these agreements. In March 2011, SES entered into a precedent agreement with Millennium Pipeline Company, L.L.C. pursuant to which it will enter into short and long term firm gas transportation services on Millennium's existing system and expansions of the system expected to be in-service by late 2012 and late 2013. Certain of SES's obligations under the precedent agreement are subject to the satisfaction of conditions precedent. On June 30, 2011, SES entered into a long term agreement with Bluestone Gathering, a wholly owned subsidiary of DTE Energy Company, pursuant to which Bluestone Gathering will build and operate a natural gas gathering system in Susquehanna County, Pennsylvania and Broome County, New York, and provide gathering services to SES in support of a portion of the Company's future Marcellus Shale natural gas production. The projected in-service date for the gathering system is as early as the second quarter of 2012. SES also executed firm transportation agreements with Tennessee Gas Pipeline that increase the Company's ability to move its Marcellus Shale natural gas production in the short term to market. As of June 30, 2011, SES's obligations for demand and similar charges under the firm transportation agreements totaled approximately $121.3 million and the Company currently has no guarantee obligations with respect to the firm transportation agreements and the gathering project and services.

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 $47 million Canadian dollars ("CAD") in the aggregate over a three year period. 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, 2011, 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. Environmental and cleanup related costs of a non-capital nature are accrued when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on the financial position or reported results of operations of the Company.

Litigation

In February 2009, SEPCO was added as a defendant in a Third Amended Petition in the matter of Tovah Energy, LLC and Toby Berry-Helfand v. David Michael Grimes, et, al. In the Sixth Amended Petition, filed in July 2010, in the 273 rd District Court in Shelby County, Texas (collectively, the "Sixth Petition") plaintiff alleged that, in 2005, they provided SEPCO with proprietary data regarding two prospects in the James Lime formation pursuant to a confidentiality agreement and that SEPCO refused to return the proprietary data to the plaintiff, subsequently acquired leases based upon such proprietary data and profited therefrom. Among other things, the plaintiff's allegations in the

Sixth Petition included various statutory and common law claims, including, but not limited to claims of misappropriation of trade secrets, violation of the Texas Theft Liability Act, breach of fiduciary duty and confidential relationships, various fraud based claims and breach of contract, including a claim of breach of a purported right of first refusal on all interests acquired by SEPCO between February 15, 2005 and February 15, 2006. In the Sixth Petition, plaintiff sought actual damages of over $55 million as well as other remedies, including special damages and punitive damages of four times the amount of actual damages established at trial.

Immediately before the commencement of the trial in November 2010, plaintiff was permitted, over SEPCO's objections, to file a Seventh Amended Petition claiming actual damages of $46 million and also seeking the equitable remedy of disgorgement of all profits for the misappropriation of trade secrets and the breach of fiduciary duty claims. In December 2010, the jury found in favor of the plaintiff with respect to all of the statutory and common law claims and awarded $11.4 million in compensatory damages. The jury did not, however, award the plaintiff any special, punitive or other damages. In addition, the jury separately determined that SEPCO's profits for purposes of disgorgement were $381.5 million. This profit determination does not constitute a judgment or an award. The plaintiff's entitlement to disgorgement of profits as an equitable remedy will be determined by the judge and it is within the judge's discretion to award none, some or all the amount of profit to the plaintiff. On December 31, 2010, the plaintiff filed a motion to enter the judgment based on the jury's verdict. On February 11, 2011, SEPCO filed a motion for a judgment notwithstanding the verdict and a motion to disregard certain findings. On March 11, 2011, the plaintiff filed an amended motion for judgment and intervenor filed its motion for judgment seeking not only the monetary damages and the profits determined by the jury but also seeking, as a new remedy, a constructive trust for profits from 143 wells as well as future drilling and sales of properties in the prospect areas. A hearing on the post-verdict motions was held on March 14, 2011. At the suggestion of the judge, all parties voluntarily agreed to participate in non-binding mediation efforts. The mediation occurred on April 6, 2011 and was unsuccessful. On June 6, 2011, SEPCO received by mail a letter dated June 2, 2011 from the judge, in which he made certain rulings with respect to the post-verdict motions and responses filed by the parties. In his rulings, the judge denied SEPCO's motion for judgment, judgment notwithstanding the verdict and to disregard certain findings. Plaintiff's and intervenor's claim for a constructive trust was denied but the judge ruled that plaintiff and intervenor shall recover from SEPCO $11.4 million and a reasonable attorney's fee of 40% of the total damages awarded and are entitled to recover on their claim for disgorgement. The judge instructed that SEPCO calculate the profit on the designated wells for each respective period. SEPCO performed the calculation and provided it to the judge in June 2011. On July 5, 2011, plaintiff and intervenor filed a letter with the court raising objections to the accounting provided by SEPCO, to which SEPCO filed a response on July 11, 2011. On July 12, 2011, the judge sent a letter to the parties in which he ruled that after reviewing the parties' respective position letters, he was awarding $23.9 million in disgorgement damages in favor of the plaintiff and intervenor. In the July 12, 2011 letter, the judge instructed the plaintiff and intervenor to prepare a judgment for his approval prior to July 21, 2011 consistent with his findings in his June 2, 2011 letter and the disgorgement award. Plaintiff and intervenor have not complied with the court's instructions as of the date hereof and, on July 14, 2011, requested an oral hearing, to which SEPCO filed its objections on July 18, 2011. SEPCO does not believe that the foregoing rulings by the judge constitute the entry of a judgment at this time. However, the Company currently expects that the entry of a judgment against SEPCO will be consistent with these rulings, and therefore will be adverse.

If an adverse judgment is entered against SEPCO, the Company believes that SEPCO has a number of legal grounds for appealing the judgment, all of which will be vigorously pursued. Based on the Company's understanding and judgment of the facts and merits of this case, including appellate defenses, and after considering the advice of counsel, the Company has determined that, although reasonably possible after exhaustion of all appeals, an adverse final outcome to this lawsuit is not probable. As such, the Company has not accrued any amounts with respect to this lawsuit. If the plaintiff and intervenor were to ultimately prevail in the appellate process, the Company currently estimates, based on the judge's rulings to date, that SEPCO's potential liability would be in the range of zero to $35.3 million, excluding interest and attorney's fees. The Company's assessment may change in the future due to occurrence of certain events, such as denied appeals, and such re-assessment could lead to the determination that the potential liability is probable and could be material to the Company's results of operations, financial position or cash flows.

In March 2010, the Company's subsidiary, SEECO, Inc., was served with a subpoena from a federal grand jury in Little Rock, Arkansas. Based on the documents requested under the subpoena and subsequent discussions described below, the Company believes the grand jury is investigating matters involving approximately 27 horizontal wells operated by SEECO in Arkansas, including whether appropriate leases or permits were obtained therefor and whether royalties and other production attributable to federal lands have been properly accounted for and paid. The Company believes it has fully complied with all requests related to the federal subpoena and delivered its affidavit to that effect. The Company and representatives of the Bureau of Land Management and the U.S. Attorney have had discussions since the production of the documents pursuant to the subpoena. In January 2011, the Company voluntarily produced additional materials informally requested by the government arising from these discussions. Although, to the Company's knowledge, no proceeding in this matter has been initiated against SEECO, the Company cannot predict whether or when one might be initiated. The Company intends to fully comply with any further requests and to cooperate with any related investigation. No assurance can be made as to the time or resources that will need to be devoted to this inquiry or the impact of the final outcome of the discussions or any related proceeding.

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

(11) INTEREST AND INCOME TAXES

The following table provides interest and income taxes paid for the three- and six-month periods ended June 30, 2011 and 2010:

	For the three months ended June 30,		For the six months ended June 30,	
	2011	2010	2011	2010
	(in thousands)			
Interest payments	$ 6,991	$ 4,093	$ 31,848	$ 27,950
Income tax payments	$ 1,000	$ 2,700	$ 17,000	$ 2,700

(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 for the three- and six-month periods ended June 30, 2011 and 2010:

	Pension Benefits			
	For the three months ended June 30,		For the six months ended June 30,	
	2011	2010	2011	2010
	(in thousands)			
Service cost	$ 2,331	$ 1,774	$ 4,662	$ 3,548
Interest cost	918	812	1,835	1,624
Expected return on plan assets	(1,100)	(876)	(2,199)	(1,752)
Amortization of prior service cost	86	87	172	173
Amortization of net loss	214	202	428	404
Net periodic benefit cost	$ 2,449	$ 1,999	$ 4,898	$ 3,997

	Postretirement Benefits			
	For the three months ended June 30,		For the six months ended June 30,	
	2011	2010	2011	2010
	(in thousands)			
Service cost	$ 339	$ 272	$ 677	$ 544
Interest cost	63	49	126	98
Amortization of transition obligation	16	16	32	32
Amortization of prior service cost	3	4	7	8
Amortization of net loss	3	5	6	10
Net periodic benefit cost	$ 424	$ 346	$ 848	$ 692

The Company currently expects to contribute $12.5 million to the pension plans and less than $0.1 million to the postretirement benefit plan in 2011. As of June 30, 2011, the Company has contributed $5.9 million to the pension plans and less than $0.1 million to the postretirement benefit plan during the year.

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 125,550 shares at June 30, 2011 compared to 156,636 shares at December 31, 2010.

(13) STOCK-BASED COMPENSATION

The Company recognized the following amounts in employee stock-based compensation costs for the three and six months ended June 30, 2011 and 2010:

	For the three months ended June 30,		For the six months ended June 30,	
	2011	2010	2011	2010
	(in thousands)			
Stock-based compensation cost – general and administrative expense	$ 2,236	$ 2,136	$ 4,686	$ 4,433
Stock-based compensation cost – capitalized	$ 1,905	$ 1,689	$ 3,815	$ 3,397

As of June 30, 2011, there was $31.8 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 2.4 years.

The following table summarizes stock option activity for the first six months of 2011 and provides information for options outstanding as of June 30, 2011.

	Number of Options	Weighted Average Exercise Price
Outstanding at December 31, 2010	4,769,122	$ 16.13
Granted	15,000	40.63
Exercised	(397,640)	8.46
Forfeited or expired	(17,001)	37.46
Outstanding at June 30, 2011	4,369,481	$ 16.83
Exercisable at June 30, 2011	3,546,494	$ 12.16

The following table summarizes restricted stock activity for the six months ended June 30, 2011 and provides information for unvested shares as of June 30, 2011.

	Number of Shares	Weighted Average Grant Date Fair Value
Unvested shares at December 31, 2010	834,058	$ 36.24
Granted	1,270	38.58
Vested	(25,818)	39.00
Forfeited	(29,729)	36.49
Unvested shares at June 30, 2011	779,781	$ 36.15

(14) 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 natural 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 2010 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 amount shown below to consolidated income before income taxes, is the sum of operating income, interest expense and other income (loss), net. The "Other" column includes items not related to the Company's reportable segments including real estate and corporate items.

	Exploration and Production	Midstream Services	Other	Total
	(in thousands)			
Three months ended June 30, 2011:				
Revenues from external customers	$ 526,969	$ 238,197	$ —	$ 765,166
Intersegment revenues	2,899	522,412	793	526,104
Operating income	222,539	59,644	359	282,542
Other income, net[1]	6	52	11	69
Depreciation, depletion and amortization expense	161,929	9,365	326	171,620
Interest expense[1]	799	5,371	—	6,170
Provision for income taxes[1]	87,492	21,349	146	108,987
Assets	5,366,199 [2]	1,095,685	280,217 [3]	6,742,101
Capital investments[4]	476,040	59,862	20,072	555,974
Three months ended June 30, 2010:				
Revenues from external customers	$ 419,149	$ 170,794	$ —	$ 589,943
Intersegment revenues	2,706	388,064	246	391,016
Operating income	162,473	43,767	77	206,317
Other income (loss), net[1]	(107)	11	12	(84)
Depreciation, depletion and amortization expense	136,905	6,986	115	144,006
Interest expense[1]	704	5,476	—	6,180
Provision for income taxes[1]	63,072	14,938	34	78,044
Assets	4,272,197 [2]	839,959	478,195 [3]	5,590,351
Capital investments[4]	441,226	89,753	12,546	543,525

	Exploration and Production	Midstream Services	Other	Total
	(in thousands)			
Six months ended June 30, 2011:				
Revenues from external customers	$ 997,625	$ 443,876	$ —	$ 1,441,501
Intersegment revenues	8,413	996,001	1,569	1,005,983
Operating income	400,822	113,561	810	515,193
Other income, net(1)	349	81	13	443
Depreciation, depletion and amortization expense	316,739	17,756	572	335,067
Interest expense(1)	3,703	9,903	—	13,606
Provision for income taxes(1)	156,874	40,769	324	197,967
Assets	5,366,199 (2)	1,095,685	280,217 (3)	6,742,101
Capital investments(4)	944,252	105,840	36,411	1,086,503
Six months ended June 30, 2010:				
Revenues from external customers	$ 904,220	$ 353,840	$ —	$ 1,258,060
Intersegment revenues	9,704	836,661	492	846,857
Operating income	412,904	81,391	112	494,407
Other income (loss), net(1)	(152)	79	12	(61)
Depreciation, depletion and amortization expense	269,612	13,147	264	283,023
Interest expense(1)	3,004	9,684	—	12,688
Provision for income taxes(1)	159,837	27,997	47	187,881
Assets	4,272,197 (2)	839,959	478,195 (3)	5,590,351
Capital investments(4)	852,659	139,019	25,472	1,017,150

(1) Interest income, interest expense and the provision 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 not directly related to gas and oil property acquisition, exploration and development activities.
(3) Other assets represent corporate assets not allocated to segments and assets, including restricted cash and investments in cash equivalents, for non-reportable segments.
(4) Capital investments include an increase of $56.4 million and a reduction of $2.3 million for the three-month periods ended June 30, 2011 and 2010, respectively, and increases of $57.9 million and $25.0 million for the six-month periods ended June 30, 2011 and 2010, respectively, relating to the change in accrued expenditures between periods.

Included in intersegment revenues of the Midstream Services segment are $456.7 million and $335.1 million for the three months ended June 30, 2011 and 2010, respectively, and $867.9 million and $741.0 million for the six months ended June 30, 2011 and 2010, 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 are allocated to the segments. For the three months ended June 30, 2011 and 2010, capital investments within the E&P segment include $5.4 million and $7.3 million, respectively, related to the Company's activities in Canada. For the six months ended June 30, 2011 and 2010, capital investments within the E&P segment include $7.8 million and $7.3 million, respectively, related to the Company's activities in Canada. At June 30, 2011, assets include $18.4 million and at June 30, 2010, assets include $7.3 million related to the Company's activities in Canada.

(15) NEW ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

On May 12, 2011, the FASB issued guidance on fair value measurement and disclosure requirements outlined in Accounting Standards Update No. 2011-04, *Fair Value Measurement (Topic 820)–Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS* ("Update 2011-04"). Update 2011-04 expands existing fair value disclosure requirements, particularly for Level 3 inputs, including: quantitative disclosure of the unobservable inputs and assumptions used in the measurement; description of the valuation processes in place and sensitivity of the fair value to changes in unobservable inputs and interrelationships between those inputs; the level of items (in the fair value hierarchy) that are not measured at fair value in the balance sheet but whose fair value must be disclosed; and the use of a nonfinancial asset if it differs from the highest and best use assumed in the fair value measurement. The amendments in Update 2011-04 must be applied prospectively and are effective during interim and annual periods beginning after December 15, 2011. The implementation of the disclosure requirement is not expected to have a material impact on the Company's consolidated financial statements.

On June 16, 2011, the FASB issued Accounting Standards Update No. 2011-05, *Presentation of Comprehensive Income* ("Update 2011-05"), which amends Topic 200, *Comprehensive Income*. Update 2011-05 eliminates the option to present components of 'other comprehensive income' ("OCI") in the statement of changes in stockholders' equity, and requires presentation of total comprehensive income and components of net income in a single statement of comprehensive income, or in two separate, consecutive statements. Update 2011-05 requires presentation of reclassification adjustments for items transferred from OCI to net income on the face of the financial statements where the components of net income and the components of OCI are presented. The amendments do not change current treatment of items in OCI, transfer of items from OCI, or reporting items in OCI net of the related tax impact. Update 2011-05 is effective for fiscal years and interim periods beginning after December 15, 2011. The implementation of these changes is not expected to have an impact on the Company's results of operations, financial position or cash flows.

(16) CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The Company is providing condensed consolidating financial information for SEECO, SEPCO and SES, its subsidiaries that are currently guarantors of the Company's registered public debt, and for its other subsidiaries that are not guarantors of such debt. These wholly owned subsidiary guarantors have jointly and severally, fully and unconditionally guaranteed the Company's 7.35% Senior Notes and 7.125% Senior Notes. The subsidiary guarantees (i) rank equally in right of payment with all of the existing and future senior debt of the subsidiary guarantors; (ii) rank senior to all of the existing and future subordinated debt of the subsidiary guarantors; (iii) are effectively subordinated to any future secured obligations of the subsidiary guarantors to the extent of the value of the assets securing such obligations; and (iv) are structurally subordinated to all debt and other obligations of the subsidiaries of the guarantors.

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

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Unaudited)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
Three months ended June 30, 2011:					
Operating revenues	$ —	$ 728,430	$ 100,108	$ (63,372)	$ 765,166
Operating costs and expenses:					
Gas purchases – midstream services	—	200,420	—	(368)	200,052
Operating expenses	—	88,477	28,793	(62,216)	55,054
General and administrative expenses	—	35,298	5,728	(788)	40,238
Depreciation, depletion and amortization	—	161,699	9,921	—	171,620
Taxes, other than income taxes	—	13,568	2,092	—	15,660
Total operating costs and expenses	—	499,462	46,534	(63,372)	482,624
Operating income	—	228,968	53,574	—	282,542
Other income, net	—	16	53	—	69
Equity in earnings of subsidiaries	167,454	—	—	(167,454)	—
Interest expense	—	1,748	4,422	—	6,170
Income (loss) before income taxes	167,454	227,236	49,205	(167,454)	276,441
Provision for income taxes	—	89,651	19,336	—	108,987
Net income (loss)	167,454	137,585	29,869	(167,454)	167,454
Less: Net loss attributable to noncontrolling interest	—	—	—	—	—
Net income (loss) attributable to Southwestern Energy	$ 167,454	$ 137,585	$ 29,869	$ (167,454)	$ 167,454
Three months ended June 30, 2010:					
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), net	—	(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

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Unaudited)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
Six months ended June 30, 2011:					
Operating revenues	$ —	$ 1,370,273	$ 193,766	$ (122,538)	$ 1,441,501
Operating costs and expenses:					
Gas purchases – midstream services	—	371,002	—	(720)	370,282
Operating expenses	—	175,329	56,777	(120,254)	111,852
General and administrative expenses	—	67,342	11,577	(1,564)	77,355
Depreciation, depletion and amortization	—	316,100	18,967	—	335,067
Taxes, other than income taxes	—	27,475	4,277	—	31,752
Total operating costs and expenses	—	957,248	91,598	(122,538)	926,308
Operating income	—	413,025	102,168	—	515,193
Other income, net	—	361	82	—	443
Equity in earnings of subsidiaries	304,063	—	—	(304,063)	—
Interest expense	—	5,393	8,213	—	13,606
Income (loss) before income taxes	304,063	407,993	94,037	(304,063)	502,030
Provision for income taxes	—	161,013	36,954	—	197,967
Net income (loss)	304,063	246,980	57,083	(304,063)	304,063
Less: Net loss attributable to noncontrolling interest	—	—	—	—	—
Net income (loss) attributable to Southwestern Energy	$ 304,063	$ 246,980	$ 57,083	$ (304,063)	$ 304,063
Six months ended June 30, 2010:					
Operating revenues	$ —	$ 1,204,589	$ 142,023	$ (88,552)	$ 1,258,060
Operating costs and expenses:					
Gas purchases – midstream services	—	300,285	—	(825)	299,460
Operating expenses	—	133,139	41,604	(87,234)	87,509
General and administrative expenses	—	60,229	9,841	(493)	69,577
Depreciation, depletion and amortization	—	269,015	14,008	—	283,023
Taxes, other than income taxes	—	21,447	2,637	—	24,084
Total operating costs and expenses	—	784,115	68,090	(88,552)	763,653
Operating income	—	420,474	73,933	—	494,407
Other income (loss)	—	(140)	79	—	(61)
Equity in earnings of subsidiaries	293,866	—	—	(293,866)	—
Interest expense	—	3,810	8,878	—	12,688
Income (loss) before income taxes	293,866	416,524	65,134	(293,866)	481,658
Provision for income taxes	—	162,479	25,402	—	187,881
Net income (loss)	293,866	254,045	39,732	(293,866)	293,777
Less: Net loss attributable to noncontrolling interest	—	(89)	—	—	(89)
Net income (loss) attributable to Southwestern Energy	$ 293,866	$ 254,134	$ 39,732	$ (293,866)	$ 293,866

CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
June 30, 2011:					
ASSETS					
Cash and cash equivalents	$ 13,180	$ —	$ 99	$ —	$ 13,279
Restricted cash	85,002	—	—	—	85,002
Accounts receivable	1,485	317,346	17,886	—	336,717
Inventories	43	32,527	808	—	33,378
Other current assets	3,875	210,008	3,883	—	217,766
Total current assets	103,585	559,881	22,676	—	686,142
Intercompany receivables	1,792,206	50	20,204	(1,812,460)	—
Property and equipment	158,583	8,738,206	1,077,035	—	9,973,824
Less: Accumulated depreciation, depletion and amortization	59,499	3,870,668	112,591	—	4,042,758
	99,084	4,867,538	964,444	—	5,931,066
Investments in subsidiaries (equity method)	2,589,149	—	—	(2,589,149)	—
Other assets	26,085	75,935	22,873	—	124,893
Total assets	$ 4,610,109	$ 5,503,404	$ 1,030,197	$ (4,401,609)	$ 6,742,101
LIABILITIES AND EQUITY					
Accounts and notes payable	$ 136,963	$ 394,049	$ 63,902	$ —	$ 594,914
Other current liabilities	3,364	166,879	2,192	—	172,435
Total current liabilities	140,327	560,928	66,094	—	767,349
Intercompany payables	—	1,315,642	496,818	(1,812,460)	—
Long-term debt	1,215,400	—	—	—	1,215,400
Deferred income taxes	(97,937)	1,221,864	200,043	—	1,323,970
Other liabilities	45,888	80,409	2,654	—	128,951
Total liabilities	1,303,678	3,178,843	765,609	(1,812,460)	3,435,670
Commitments and contingencies					
Total equity	3,306,431	2,324,561	264,588	(2,589,149)	3,306,431
Total liabilities and equity	$ 4,610,109	$ 5,503,404	$ 1,030,197	$ (4,401,609)	$ 6,742,101

CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
December 31, 2010:					
ASSETS					
Cash and cash equivalents	$ 8,381	$ 7,631	$ 43	$ —	$ 16,055
Accounts receivable	382	331,154	20,037	—	351,573
Inventories	—	34,263	835	—	35,098
Other current assets	5,015	171,060	2,092	—	178,167
Total current assets	13,778	544,108	23,007	—	580,893
Intercompany receivables	1,820,857	131	18,724	(1,839,712)	—
Investments	—	11,103	(11,102)	(1)	—
Property and equipment	124,823	7,871,279	984,783	—	8,980,885
Less: Accumulated depreciation, depletion and amortization	52,256	3,526,010	104,422	—	3,682,688
	72,567	4,345,269	880,361	—	5,298,197
Investments in subsidiaries (equity method)	2,253,871	—	—	(2,253,871)	—
Other assets	18,918	92,747	26,708	—	138,373
Total assets	$ 4,179,991	$ 4,993,358	$ 937,698	$ (4,093,584)	$ 6,017,463
LIABILITIES AND EQUITY					
Accounts and notes payable	$ 175,476	$ 336,411	$ 33,208	$ —	$ 545,095
Other current liabilities	3,288	142,839	2,761	—	148,888
Total current liabilities	178,764	479,250	35,969	—	693,983
Intercompany payable	—	1,317,696	522,017	(1,839,713)	—
Long-term debt	1,093,000	—	—	—	1,093,000
Deferred income taxes	(98,206)	1,066,166	162,332	—	1,130,292
Other liabilities	41,557	89,986	3,769	—	135,312
Total liabilities	1,215,115	2,953,098	724,087	(1,839,713)	3,052,587
Commitments and contingencies					
Total equity	2,964,876	2,040,260	213,611	(2,253,871)	2,964,876
Total liabilities and equity	$ 4,179,991	$ 4,993,358	$ 937,698	$ (4,093,584)	$ 6,017,463

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Unaudited)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
Six months ended June 30, 2011:					
Net cash provided by (used in) operating activities	$ (29,781)	$ 763,933	$ 122,778	$ —	$ 856,930
Investing activities:					
Capital investments	(35,347)	(889,700)	(99,611)	—	(1,024,658)
Proceeds from sale of property and equipment	—	120,892	241	—	121,133
Transfers to restricted cash	(85,002)	—	—	—	(85,002)
Other	7,244	(11,339)	7,974	—	3,879
Net cash used in investing activities	(113,105)	(780,147)	(91,396)	—	(984,648)
Financing activities:					
Intercompany activities	22,870	8,583	(31,453)	—	—
Payments on current portion of long-term debt	(600)	—	—	—	(600)
Payments on revolving long-term debt	(1,717,600)	—	—	—	(1,717,600)
Borrowings under revolving long-term debt	1,840,600	—	—	—	1,840,600
Other items	2,415	—	—	—	2,415
Net cash provided by (used in) financing activities	147,685	8,583	(31,453)	—	124,815
Effect of exchange rate changes on cash	—	—	127	—	127
Increase (decrease) in cash and cash equivalents	4,799	(7,631)	56	—	(2,776)
Cash and cash equivalents at beginning of year	8,381	7,631	43	—	16,055
Cash and cash equivalents at end of period	$ 13,180	$ —	$ 99	$ —	$ 13,279
Six months ended June 30, 2010:					
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
Transfers to 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

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 2010 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, 2011 and 2010. 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 2010 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 2010 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 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 the development of an unconventional gas reservoir located on the Arkansas side of the Arkoma Basin, which we refer to as the Fayetteville Shale play. We are also actively engaged in exploration and production activities in Texas, Pennsylvania and, to a lesser extent, in Oklahoma. In 2010, we commenced an exploration program in New Brunswick, Canada, which represents our first operations outside of the United States.

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 our ongoing development of the Fayetteville Shale play in Arkansas and the Marcellus Shale play in Pennsylvania. 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. 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, 2011 Compared with Three Months Ended June 30, 2010

We reported net income attributable to Southwestern Energy of $167.5 million for the three months ended June 30, 2011, or $0.48 per diluted share, compared to net income attributable to Southwestern Energy of $122.1 million, or $0.35 per diluted share, for the comparable period in 2010.

Our natural gas and oil production increased to 122.8 Bcfe for the three months ended June 30, 2011, up 25% from the three months ended June 30, 2010. The 24.5 Bcfe increase in our second quarter 2011 production was primarily due to a 23.8 Bcf increase in net production from our Fayetteville Shale play and a 5.1 Bcf increase in net production from our Marcellus Shale properties, which more than offset a combined 4.4 Bcfe decrease in net production from our East Texas and Arkoma Basin properties. The average price realized for our gas production, including the effects of hedges, increased slightly to $4.30 per Mcf for the three months ended June 30, 2011 compared to $4.27 per Mcf for the same period in 2010.

Our E&P segment reported operating income of $222.5 million for the three months ended June 30, 2011 compared to operating income of $162.5 million for the same period in 2010. The increase in operating income was due primarily to a $105.1 million increase in revenues due to higher natural gas production volumes and a $4.0 million increase in revenues due to higher realized prices on our natural gas production, partially offset by a $47.9 million increase in our operating costs and expenses associated with the natural gas production increase.

Operating income for our Midstream Services segment was $59.6 million for the three months ended June 30, 2011, up from $43.8 million for the three months ended June 30, 2010, due to an increase of $24.9 million in gas gathering revenues and an increase of $1.9 million in the margin generated from our gas marketing activities, which were partially offset by an $11.0 million increase in operating costs and expenses, exclusive of gas purchase costs.

Capital investments were $556.0 million for the three months ended June 30, 2011, of which $476.0 million was invested in our E&P segment, compared to $543.5 million for the same period of 2010, of which $441.2 million was invested in our E&P segment.

Six Months Ended June 30, 2011 Compared with Six Months Ended June 30, 2010

We reported net income attributable to Southwestern Energy of $304.1 million for the six months ended June 30, 2011, or $0.87 per diluted share, up $10.2 million from $293.9 million, or $0.84 per diluted share, for the comparable period in 2010.

Our natural gas and oil production increased to 237.8 Bcfe for the six months ended June 30, 2011, up 26% from 188.3 Bcfe for the six months ended June 30, 2010. The 49.5 Bcfe increase in 2011 production was primarily due to a 49.4 Bcf increase in net production from our Fayetteville Shale play and a 7.9 Bcf increase in net production from our Marcellus Shale properties, which more than offset a combined 7.8 Bcfe decrease in net production from our East Texas and Arkoma Basin properties. The average price realized for our gas production, including the effects of hedges, decreased approximately 13% to $4.21 per Mcf for the six months ended June 30, 2011 compared to the same period in 2010.

Our E&P segment reported operating income of $400.8 million for the six months ended June 30, 2011, down from $412.9 million for the six months ended June 30, 2010. The decrease in operating income was due to a $240.0 million increase in revenues due to higher natural gas production volumes, which was more than offset by a $144.4 million decrease in revenues due to lower realized gas prices and a $104.2 million increase in our operating costs and expenses associated with the natural gas production increase.

Operating income for our Midstream Services segment was $113.6 million for the six months ended June 30, 2011, up from $81.4 million for the six months ended June 30, 2010, due to an increase of $50.8 million in gas gathering revenues and an increase of $4.3 million in the margin generated from our gas marketing activities, which were partially offset by a $23.0 million increase in operating costs and expenses, exclusive of gas purchase costs.

Net cash provided by operating activities increased 6% to $856.9 million for the six months ended June 30, 2011 up from $809.1 million for the same period in 2010, due to an increase in net income adjusted for non-cash expenses primarily resulting from increased revenues due to higher natural gas production and gathering volumes, partially offset by lower realized gas prices and a decrease in changes in working capital. Capital investments were $1,086.5 million for the six months ended June 30, 2011, of which $944.3 million was invested in our E&P segment, compared to $1,017.2 million for the same period of 2010, of which $852.7 million was invested in our E&P segment.

Recent Development

Sale of Certain East Texas Properties

In the second quarter of 2011, the Company sold certain oil and gas leases, wells and gathering equipment in Shelby, San Augustine, and Sabine Counties in East Texas for approximately $108.1 million, before customary purchase price adjustments. This divestiture included only the Haynesville and Middle Bossier Shale intervals in the affected acreage, which intervals had net production of approximately 7.0 MMcf per day as of May 25, 2011 and proved net reserves of approximately 25.1 Bcf at December 31, 2010. Under full cost accounting, this divestiture was accounted for as an adjustment of capitalized gas and oil properties with no gain recognized.

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, income tax expense and stock-based compensation are discussed on a consolidated basis.

Exploration and Production

	For the three months ended June 30,		For the six months ended June 30,	
	2011	2010	2011	2010
Revenues (in thousands)	$ 529,868	$ 421,855	$ 1,006,038	$ 913,924
Operating costs and expenses (in thousands)	$ 307,329	$ 259,382	$ 605,216	$ 501,020
Operating income (in thousands)	$ 222,539	$ 162,473	$ 400,822	$ 412,904
Gas production (Bcf)	122.6	98.0	237.5	187.7
Oil production (MBbls)	25	47	55	93
Total production (Bcfe)	122.8	98.3	237.8	188.3
Average gas price per Mcf, including hedges	$ 4.30	$ 4.27	$ 4.21	$ 4.82
Average gas price per Mcf, excluding hedges	$ 3.84	$ 3.69	$ 3.76	$ 4.25
Average oil price per Bbl	$ 100.32	$ 76.17	$ 95.86	$ 75.87
Average unit costs per Mcfe:				
Lease operating expenses	$ 0.80	$ 0.85	$ 0.83	$ 0.81
General & administrative expenses	$ 0.27	$ 0.31	$ 0.27	$ 0.30
Taxes, other than income taxes	$ 0.11	$ 0.09	$ 0.11	$ 0.11
Full cost pool amortization	$ 1.28	$ 1.33	$ 1.30	$ 1.37

Revenues

Revenues for our E&P segment were up $108.0 million, or 26%, for the three months ended June 30, 2011 compared to the same period in 2010. Higher natural gas production volumes in the second quarter of 2011 increased revenues by $105.1 million and higher realized prices for our gas production increased revenue by $4.0 million compared to the second quarter of 2010. E&P revenues were up $92.1 million, or 10% for the six months ended June 30, 2011. Higher natural gas production volumes in the first six months of 2011 increased revenues by $240.0 million while lower realized prices for our gas production decreased revenue by $144.4 million. We expect our natural gas production volumes to continue to increase due to our development of the Fayetteville Shale play in Arkansas and the Marcellus Shale play in Pennsylvania. Natural gas and oil prices are difficult to predict and subject to wide price fluctuations. As of July 26, 2011, we had hedged 159.9 Bcf of our remaining 2011 gas production, 265.7 Bcf of our 2012 gas production and 185.2 Bcf of our 2013 gas production to limit our exposure to price fluctuations. We refer you to Note 7 to the unaudited condensed consolidated financial statements included in this Form 10-Q and to the discussion of “Commodity Prices” provided below for additional information.

Production

For the three months ended June 30, 2011, our natural gas and oil production increased 25% to 122.8 Bcfe, up from 98.3 Bcfe from the same period in 2010, and was produced entirely by our properties in the United States. The 24.5 Bcfe increase in our 2011 production was primarily due to a 23.8 Bcf increase in net production from our Fayetteville Shale play and a 5.1 Bcf increase in net production from our Marcellus Shale properties, which more than offset a combined 4.4 Bcfe decrease in net production from our East Texas and Arkoma Basin properties. Natural gas production represented nearly 100% of our total production for the three months ended June 30, 2011 and was up approximately 25% to 122.6 Bcf compared to the same period in 2010. Net production from our Fayetteville Shale and Marcellus Shale properties was 107.4 Bcf and 5.1 Bcf, respectively, for the three months ended June 30, 2011 compared to 83.6 Bcf and zero Bcf, respectively, for the same period in 2010. For the six months ended June 30, 2011, our natural gas and oil production increased 26% to 237.8 Bcfe, up from 188.3 Bcfe from the same period in 2010, and was produced entirely by our properties in the United States. The 49.5 Bcfe increase in our 2011 production was primarily due to a 49.4 Bcf increase in net natural gas production from our Fayetteville Shale play and a 7.9 Bcf increase in net production from our Marcellus Shale properties, which more than offset a combined 7.8 Bcfe decrease in net production from our East Texas and Arkoma Basin properties. Natural gas production represented nearly 100% of our total production for the six months ended June 30, 2011 and was up approximately 27% to 237.5 Bcf compared to the same period in 2010. Net production from our Fayetteville Shale and Marcellus Shale properties was 208.5 Bcf and 7.9 Bcf, respectively, for the six months ended June 30, 2011 compared to 159.1 Bcf and zero Bcf, respectively, for the same period in 2010.

Commodity Prices

The average price realized for our natural gas production, including the effects of hedges, increased slightly to $4.30 per Mcf for the three months ended June 30, 2011, as compared to the same period in 2010. The slight increase was the result of a $0.15 Mcf increase in average gas prices, excluding hedges, mostly offset by the decreased effect of our price hedging activities. The average price realized for our natural gas production, including the effects of hedges, decreased 13% to $4.21 per Mcf for the six months ended June 30, 2011, as compared to the same period in 2010. The decrease in the average price realized for six months ended June 30, 2011, as compared to the same period in 2010, primarily reflects the decrease in average gas prices, excluding hedges, in addition to the decreased effect of our price hedging activities. 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 basis 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).

Disregarding the impact of hedges, the average price received for our natural gas production for the three months ended June 30, 2011 of $3.84 per Mcf was approximately $0.15 per Mcf higher than the three months ended June 30, 2010. Our hedging activities increased the average gas price $0.46 per Mcf for the three months ended June 30, 2011 compared to an increase of $0.58 per Mcf for the same period in 2010. Disregarding the impact of hedges, the average price received for our natural gas production for the six months ended June 30, 2011 of $3.76 per Mcf was approximately $0.49 per Mcf lower than the six months ended June 30, 2010. Our hedging activities increased the average gas price $0.45 per Mcf for the six months ended June 30, 2011 compared to an increase of $0.57 per Mcf for the same period in 2010.

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. Excluding the impact of hedges, the average price received for our natural gas production for the six months ended June 30, 2011 of $3.76 per Mcf was approximately $0.45 lower than the average monthly NYMEX settlement price, primarily due to locational basis differentials and transportation costs. We had protected approximately 54% of our gas production for the six months ended June 30, 2011 from the impact of widening basis differentials through our hedging activities and sales arrangements. For the remainder of 2011, we expect our total gas sales discount to NYMEX to be $0.45 to $0.50 per Mcf. At June 30, 2011, we had basis protected on approximately 118 Bcf of our remaining 2011 expected gas production through financial hedging activities and physical sales arrangements at a differential to NYMEX gas prices of approximately ($0.02) per Mcf, excluding transportation and fuel charges. Additionally, at June 30, 2011, we had basis protected on approximately 77 Bcf of our 2012 expected gas production and 21 Bcf of our 2013 expected gas production through financial hedging activities and physical sales arrangements.

In addition to the basis hedges discussed above, at June 30, 2011, we had NYMEX fixed price hedges in place on notional volumes of 128.6 Bcf of our remaining 2011 natural gas production at an average price of $5.24 per MMBtu and collars in place on notional volumes of 31.3 Bcf of our remaining 2011 gas production at an average floor and ceiling price of $5.09 and $6.50 per MMBtu, respectively.

As of June 30, 2011, we had NYMEX fixed price hedges in place on notional volumes of 185.2 Bcf and 185.2 Bcf of our 2012 and 2013 natural gas production, respectively, and we had collars in place on notional volumes of 80.5 Bcf of our 2012 natural gas production.

Operating Income

Operating income from our E&P segment was $222.5 million for the three months ended June 30, 2011 compared to operating income of $162.5 million for the same period in 2010. The increase in operating income was primarily due to the increase in revenue attributable to our 25% increase in production, which more than offset the $47.9 million increase in our operating costs and expenses associated with our increase in natural gas production. Operating income from our E&P segment decreased to $400.8 million for the six months ended June 30, 2011 compared to operating income of $412.9 million for the same period in 2010. Operating income decreased as the increase in revenue attributable to our 26% increase in production was more than offset by the decrease in revenue attributable to the 13% decline in realized gas prices and the $104.2 million increase in our operating costs and expenses associated with our increase in natural gas production.

Operating Costs and Expenses

Lease operating expenses per Mcfe for our E&P segment were $0.80 for three months ended June 30, 2011 compared to $0.85 for the same period in 2010. The decrease in lease operating expenses per unit of production for the three months ended June 30, 2011, was primarily due to a decrease in salt water disposal costs in our Fayetteville Shale play. Lease operating expenses per Mcfe for our E&P segment were $0.83 for the six months ended June 30, 2011 compared to $0.81 for the same period in 2010. The increase in lease operating expense per unit of production for the six months ended June 30, 2011, was primarily due to increased gathering and treating costs related to our Fayetteville Shale play.

General and administrative expenses per Mcfe decreased 13% to $0.27 for the three months ended June 30, 2011 and decreased 10% to $0.27 for the six months ended June 30, 2011, reflecting the effects of our increased production volumes. In total, general and administrative expenses for our E&P segment were $33.6 million for the three months ended June 30, 2011 compared to $30.4 million for the same period in 2010, and were $64.1 million for the six months ended June 30, 2011 compared to $56.7 million for the same period in 2010. Payroll, employee incentive compensation, and other employee-related costs associated with our E&P operations increased by $1.5 million for the three months ended June 30, 2011 and $2.7 million for the six months ended June 30, 2011 compared to the same periods in 2010 primarily as a result of the expansion of our E&P operations.

Taxes other than income taxes per Mcfe increased to $0.11 for the three months ended June 30, 2011 compared to $0.09 for the same period in 2010 and remained flat at $0.11 for the six months ended June 30, 2011 and 2010. 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 $1.28 per Mcfe for the three months ended June 30, 2011 compared to $1.33 per Mcfe for the same period in 2010. The decline in the average amortization rate for the three months ended June 30, 2011 compared to the same period of 2010 was primarily the result of lower acquisition and development costs, combined with the sale of certain East Texas oil and natural gas leases and wells in the second quarter of 2010, as the proceeds from the sale were appropriately credited to the full cost pool. For the first six months of 2011, our full cost pool amortization rate averaged $1.30 per Mcfe compared to $1.37 per Mcfe for the same period in 2010. The decline in the average amortization rate for the six months ended June 30, 2011 compared to the same period of 2010 was primarily due to the sale of certain East Texas oil and natural gas leases and wells in the second quarter of 2010, as the proceeds from the sale were appropriately credited to the full cost pool, combined with lower acquisition and development costs. The amortization rate is impacted by the timing and amount of reserve additions and the costs associated with those additions, revisions of previous reserve estimates due to both price and well performance, write-downs that result from full cost ceiling tests, proceeds from the sale of properties that reduce the full cost pool and the levels of costs subject to amortization. We cannot predict our future full cost pool amortization rate with accuracy due to the variability of each of the factors discussed above, as well as other factors, including but not limited to the uncertainty of the amount of future reserves attributed to our Fayetteville Shale play.

Unevaluated costs excluded from amortization were $806.4 million at June 30, 2011 compared to $712.1 million at December 31, 2010. The increase in unevaluated costs since December 31, 2010 primarily resulted from a $47.1 million increase in our drilling activity in our wells in progress, a $34.2 million increase in our undeveloped leasehold acreage and seismic costs. Unevaluated costs excluded from amortization at June 30, 2011 included $18.2 million related to our properties in Canada, compared to $10.7 million at December 31, 2010.

The timing and amount of production and reserve additions could have a material adverse impact on our per unit costs.

Midstream Services

	For the three months ended June 30,		For the six months ended June 30,	
	2011	2010	2011	2010
	($ in thousands, except volumes)			
Revenues – marketing	$ 661,560	$ 484,691	$ 1,248,208	$ 1,049,679
Revenues – gathering	$ 99,049	$ 74,167	$ 191,669	$ 140,822
Gas purchases – marketing	$ 653,517	$ 478,596	$ 1,232,837	$ 1,038,599
Operating costs and expenses	$ 47,448	$ 36,495	$ 93,479	$ 70,511
Operating income	$ 59,644	$ 43,767	$ 113,561	$ 81,391
Gas volumes marketed (Bcf)	154.1	118.9	297.1	226.8
Gas volumes gathered (Bcf)	183.3	140.2	354.8	265.9

Revenues

Revenues from our marketing activities were up 36% to $661.6 million for the three months ended June 30, 2011 and were up 19% to $1,248.2 million for the six months ended June 30, 2011 compared to the respective periods of 2010. For the three months ended June 30, 2011, the volumes marketed increased 30% and the price received for volumes marketed increased 5% compared to the same period in 2010. For the six months ended June 30, 2011, the volumes marketed increased 31% and the price received for volumes marketed decreased 9% compared to the same period in 2010. 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 92% and 96% of the marketed volumes for the three months ended June 30, 2011 and 2010, respectively. For the six months ended June 30, 2011 and 2010, production from our E&P operated wells accounted for 93% and 97% of the marketed volumes, respectively.

Revenues from our gathering activities were up 34% to $99.0 million for the three months ended June 30, 2011 and up 36% to $191.7 million for the six months ended June 30, 2011 compared to the respective periods in 2010. The increases in gathering revenues resulted from a 31% increase in gas volumes gathered for the three months ended June 30, 2011 and a 33% increase in gas volumes gathered for the six months ended June 30, 2011 compared to the respective periods in 2010. Substantially all of the increases in gathering revenues for the three months ended June 30, 2011 and six months ended June 30, 2011 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 and Marcellus Shale properties are developed and production increases as expected.

Operating Income

Operating income from our Midstream Services segment increased to $59.6 million for the three months ended June 30, 2011 compared to $43.8 million for the same period in 2010 and increased to $113.6 million for the six months ended June 30, 2011 compared to $81.4 million for the same period in 2010. The increases in operating income reflect the substantial increases in gas volumes gathered which primarily resulted from our increased E&P production volumes. The $15.9 million increase in operating income for the three months ended June 30, 2011 was primarily due to an increase of $24.9 million in gathering revenues and an increase of $1.9 million in the margin generated from our gas marketing activities, which was partially offset by an $11.0 million increase in operating costs and expenses, exclusive of gas purchase costs, associated with the increase in gas volumes gathered. The $32.2 million increase in operating income for the six months ended June 30, 2011 was primarily due to an increase of $50.8 million in gathering revenues and an increase of $4.3 million in the margin generated from our gas marketing activities, which was partially offset by a $23.0 million increase in operating costs and expenses, exclusive of gas purchase costs, associated with the increase in gas volumes gathered.

The margin generated from gas marketing activities was $8.0 million for the three months ended June 30, 2011 compared to $6.1 million for the three months ended June 30, 2010. The margin generated from gas marketing activities was $15.4 million for the six months ended June 30, 2011 compared to $11.1 million for the six months ended June 30, 2010. Margins are primarily driven by volumes of gas marketed and may fluctuate depending on the prices paid for commodities and the ultimate disposition of those commodities. We enter into hedging activities from time to time with respect to our gas marketing activities to provide margin protection. We refer you to Item 3, "Quantitative and Qualitative Disclosures about Market Risks" included in this Form 10-Q for additional information.

Interest Expense

Interest expense, net of capitalization, remained flat at $6.2 million for the three months ended June 30, 2011 and June 30, 2010 respectively and increased to $13.6 million for the six months ended June 30, 2011 compared to $12.7 million for the same period in 2010. The increase in interest expense, net of capitalization, for the six-month period ended June 30, 2011 was primarily due to our increased borrowing level, partially offset by an increase in capitalized interest. We capitalized interest of $11.5 million and $20.6 million for the three- and six-month periods ended June 30, 2011, respectively, compared to $8.5 million and $16.4 million for the same periods in 2010. The increases in capitalized interest were primarily due to the increase in our costs excluded from amortization in our E&P segment.

Income Taxes

Our effective tax rates were 39.4% and 39.0% for the six months ended June 30, 2011 and 2010, respectively. For the six months ended June 30, 2011, we recorded an income tax expense of $198.0 million compared to an income tax expense of $187.9 million for the same period in 2010.

Stock-Based Compensation Expense

We expensed $2.2 million and capitalized $1.9 million for stock-based compensation during the three-month period ended June 30, 2011 compared to $2.1 million expensed and $1.7 million capitalized for the comparable period in 2010. We expensed $4.7 million and capitalized $3.8 million for stock-based compensation costs recognized during the six-month period ended June 30, 2011 compared to $4.4 million expensed and $3.4 million capitalized for the comparable period in 2010. We refer you to Note 13 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, 2011, 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 entities to provide a reconciliation of purchases, sales, issuance and settlements of anything valued with a Level 3 method, which is used to price the hardest to value instruments. The implementation did not have an impact on our results of operations, financial position or cash flows.

On May 12, 2011, the FASB issued guidance on fair value measurement and disclosure requirements outlined in Accounting Standards Update No. 2011-04, *Fair Value Measurement (Topic 820)–Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS* ("Update 2011-04"). Update 2011-04 expands existing fair value disclosure requirements, particularly for Level 3 inputs, including: quantitative disclosure of the unobservable inputs and assumptions used in the measurement; description of the valuation processes in place and sensitivity of the fair value to changes in unobservable inputs and interrelationships between those inputs; the level of items (in the fair value hierarchy) that are not measured at fair value in the balance sheet but whose fair value must be disclosed; and the use of a nonfinancial asset if it differs from the highest and best use assumed in the fair value measurement. The amendments in Update 2011-04 must be applied prospectively and are effective during interim and annual periods beginning after December 15, 2011. The implementation of the disclosure requirement is not expected to have a material impact on the Company's consolidated financial statements.

On June 16, 2011, the FASB issued Accounting Standards Update No. 2011-05, *Presentation of Comprehensive Income* ("Update 2011-05"), which amends Topic 200, *Comprehensive Income*. Update 2011-05 eliminates the option to present components of 'other comprehensive income' ("OCI") in the statement of changes in stockholders' equity, and requires presentation of total comprehensive income and components of net income in a single statement of comprehensive income, or in two separate, consecutive statements. Update 2011-05 requires presentation of reclassification adjustments for items transferred from OCI to net income on the face of the financial statements where the components of net income and the components of OCI are presented. The amendments do not change current treatment of items in OCI, transfer of items from OCI, or reporting items in OCI net of the related tax impact. Update 2011-05 is effective for fiscal years and interim periods beginning after December 15, 2011. The implementation of these changes is not expected to have an impact on the Company's results of operations, financial position or cash flows.

LIQUIDITY AND CAPITAL RESOURCES

We depend primarily on internally-generated funds, our Credit Facility and funds accessed through debt and equity markets as our primary sources of liquidity.

For the remainder of 2011, assuming natural gas prices remain at current levels, we expect to draw on a portion of the funds available under our Credit Facility to fund our planned capital investments (discussed below under "Capital Investments"), which are expected to exceed the net cash generated by our operations. We refer you to Note 9 to the consolidated financial statements included in this Form 10-Q and the section below under "Financing Requirements" for additional discussion of our Credit Facility.

Net cash provided by operating activities increased 6% to $856.9 million for the six months ended June 30, 2011 compared to $809.1 million for the same period in 2010, due to an increase in net income adjusted for non-cash expenses primarily resulting from increased revenues due to higher natural gas production and gathering volumes, partially offset by lower realized gas prices and a decrease in changes in working capital. During the six months ended June 30, 2011, requirements for our capital investments were funded primarily from our cash generated by operating activities and borrowings under our Credit Facility. For the six months ended June 30, 2011, cash generated from our operating activities funded 84% of our cash requirements for capital investments and 82% for the six months ended June 30, 2010.

At June 30, 2011 our capital structure consisted of 27% debt and 73% equity. We believe that our operating cash flow and available funds under our Credit Facility will be adequate to meet our capital and operating requirements for 2011. 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 natural gas and oil production. Natural gas and oil prices are subject to wide fluctuations and are driven by market supply and demand factors which are impacted by the overall state of the economy. The price received for our production is also influenced by our commodity hedging activities, as more fully discussed in Item 3, "Quantitative and Qualitative Disclosures about Market Risks" and 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 $1.1 billion for the six months ended June 30, 2011 compared to $1.0 billion for the same period in 2010. Our E&P segment investments were $944.3 million for the six months ended June 30, 2011 compared to $852.7 million for the same period in 2010. Our E&P segment capitalized internal costs of $73.6 million for the six months ended June 30, 2011 compared to $67.0 million for the comparable period in 2010. 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.

Our capital investments for 2011 are planned to be $2.0 billion, consisting of $1.7 billion for E&P, $225 million for Midstream Services and $60 million for corporate and other purposes. Of the approximate $1.7 billion, we expect to allocate approximately $1.25 billion to our Fayetteville Shale play. Our planned level of capital investments in 2011 is expected to allow us to continue our progress in the Fayetteville Shale and Marcellus Shale programs and explore and develop other existing natural gas and oil properties and generate new drilling prospects. Our 2011 capital investment program is expected to be funded through cash flow from operations and borrowings under our Credit Facility. The planned capital program for 2011 is flexible and can be modified, including downward, if the low natural gas price environment persists for an extended period of time. We will reevaluate our proposed investments as needed to take into account prevailing market conditions and, if natural gas prices change significantly in 2011, we could change our planned investments.

Financing Requirements

Our total debt outstanding was $1.2 billion at June 30, 2011 compared to $1.1 billion at December 31, 2010.

In February 2011, we amended and restated our unsecured revolving credit facility, increasing the borrowing capacity to $1.5 billion and extending the maturity date to February 2016. The amount available under the revolving credit facility may be increased to $2.0 billion at any time upon the Company's agreement with its existing or additional lenders. We had $544.2 million outstanding under our revolving credit facility at June 30, 2011 compared to $421.2 million at December 31, 2010.

The interest rate on our Credit Facility is calculated based upon our public debt rating and is currently 200 basis points over LIBOR. Our publicly traded notes are rated BBB- by Standard and Poor's and we have a Corporate Family Rating of Ba1 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, 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 hedging activities, pension and other postretirement liabilities as well as the effects of non-cash entries that result from any full cost ceiling impairments occurring after the date of the agreement. At June 30, 2011, our capital structure under our Credit Facility was 28% debt and 72% equity, which excluded hedging activities, pension and other postretirement liabilities but included the effect of the full cost ceiling impairment that occurred in 2009. We were in compliance with all of the covenants of our Credit Facility at June 30, 2011. Although we do not anticipate any violations of our financial covenants, our ability to comply with those covenants is dependent upon the success of our exploration and development program and upon factors beyond our control, such as the market prices for natural gas and oil. If we are unable to borrow under our Credit Facility, we may have to decrease our capital investment plans.

Our capital structure consisted of 27% debt and 73% equity at June 30, 2011 and December 31, 2010. Equity at June 30, 2011 included an accumulated other comprehensive gain of $120.1 million related to our hedging activities and a loss for $12.1 million related to our pension and other postretirement liabilities. The amount recorded in equity for our hedging activities is based on current market values for our hedges at June 30, 2011 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 July 26, 2011 we had NYMEX commodity price hedges in place on 159.9 Bcf of our remaining targeted 2011 natural gas production, 265.7 Bcf of our expected 2012 natural gas production and 185.2 Bcf of our expected 2013 natural gas production. The amount of long-term debt we incur will be dependent upon commodity prices and our capital investment plans.

Contractual Obligations and Contingent Liabilities and Commitments

During the first and second quarters of 2011, our marketing subsidiary, Southwestern Energy Services Company ("SES"), entered into a number of short and long term firm transportation service and gathering agreements in support of our growing Marcellus Shale operations in Pennsylvania and we have provided certain guarantees of a portion of SES's obligations under these agreements. In March 2011, SES entered into a precedent agreement with Millennium Pipeline Company, L.L.C. pursuant to which it will enter into short and long term firm gas transportation services on Millennium's existing system and expansions of the system expected to be in-service by late 2012 and late 2013. Certain of SES's obligations under the precedent agreement are subject to the satisfaction of conditions precedent. On June 30, 2011, SES entered into a long term agreement with Bluestone Gathering, a wholly owned subsidiary of DTE Energy Company, pursuant to which Bluestone Gathering will build and operate a natural gas gathering system in Susquehanna County, Pennsylvania and Broome County, New York, and provide gathering services to SES in support of a portion of our future Marcellus Shale natural gas production. The projected in-service date for the gathering system is as early as the second quarter of 2012. SES also executed firm transportation agreements with Tennessee Gas Pipeline that increase our ability to move our Marcellus Shale natural gas production in the short term to market. As of June 30, 2011, SES's obligations for demand and similar charges under the firm transportation agreements totaled approximately $121.3 million and we currently have no guarantee obligations with respect to the firm transportation agreements and the gathering project and services.

We have various contractual obligations in the normal course of our operations and financing activities. Other than the increase in our firm transportation commitments, there have been no material changes to our contractual obligations from those disclosed in our 2010 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 a three year period. 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. We commenced our Canada exploration program in 2010 and, as of June 30, 2011, 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 $12.5 million to our pension plans and less than $0.1 million to our postretirement benefit plan in 2011. As of June 30, 2011, we have contributed $5.9 million to our pension plans and less than $0.1 million to our postretirement benefit plan during the year. At June 30, 2011, we recognized a liability of $15.1 million as a result of the underfunded status of our pension and other postretirement benefit plans compared to a liability of $15.9 million at December 31, 2010.

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 results of operations, financial position or cash flows, 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. For further information regarding commitments and contingencies, we refer you to Note 10 in the unaudited condensed consolidated financial statements included in this Form 10-Q.

Working Capital

We had negative working capital of $81.2 million at June 30, 2011 and negative working capital of $113.1 million at December 31, 2010. Current assets increased by $105.2 million at June 30, 2011 compared to December 31, 2010, primarily due to an $85.0 million increase in restricted cash as a result of a deposit 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 2011 and we deposited $85.0 million of the proceeds from 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 $73.4 million during the six months ended June 30, 2011 primarily as a result of a $62.3 million increase in accounts payable and a $19.5 million increase in current deferred income taxes related to our hedging activities. We maintain access to funds that may be needed to meet capital requirements through our Credit Facility described in "Financing Requirements" above.

Natural Gas in Underground Storage

We record our natural gas stored in inventory that is owned by the E&P segment at the lower of weighted average cost or market. The natural 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 natural gas futures market in assessing the price we expect to be able to realize for our natural gas in inventory. A significant decline in the future market price of natural gas could result in write-downs of our natural 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. See "Commodities Risk" below for discussion of credit risk associated with commodities trading.

Interest Rate Risk

At June 30, 2011, we had $1.2 billion of total debt with a weighted average interest rate of 5.10%. Our revolving credit facility has a floating interest rate (2.165% at June 30, 2011). At June 30, 2011, we had $544.2 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 commercial banks, investment banks and integrated energy companies 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 recent volatility in the financial markets, we cannot be certain that we will not experience such losses in the future.

Exploration and Production

The following table provides information about our financial instruments that are sensitive to changes in commodity prices and that are used to hedge prices for natural 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, 2011, the fair value of our financial instruments related to natural gas production was a $199.2 million asset.

	Volume (Bcf)	Weighted Average Price to be Swapped ($/MMBtu)	Weighted Average Floor Price ($/MMBtu)	Weighted Average Ceiling Price ($/MMBtu)	Weighted Average Basis Differential ($/MMBtu)	Fair value at June 30, 2011 ($ in millions)
Natural Gas (Bcf):						
Fixed Price Swaps:						
2011 (1)	128.9	$ 5.24	$ —	$ —	$ —	$ 98.4
2012 (2)	185.7	$ 5.02	$ —	$ —	$ —	$ 33.1
2013	185.2	$ 5.06	$ —	$ —	$ —	$ (17.4)
Floating Price Swaps:						
2011	1.3	$ 4.58	$ —	$ —	$ —	$ (0.2)
2012	4.5	$ 5.70	$ —	$ —	$ —	$ (4.1)
Costless-Collars:						
2011	31.3	$ —	$ 5.09	$ 6.50	$ —	$ 21.9
2012	80.5	$ —	$ 5.50	$ 6.67	$ —	$ 67.6
Basis Swaps:						
2011	16.6	$ —	$ —	$ —	$ 0.07	$ —
2012	26.7	$ —	$ —	$ —	$ 0.15	$ (0.1)
2013	19.1	$ —	$ —	$ —	$ 0.12	$ —

(1) Includes fixed-price swaps for 0.3 Bcf relating to future sales from our underground storage facility that have a fair value asset of approximately $0.1 million.
(2) Includes fixed-price swaps for 0.5 Bcf relating to future sales from our underground storage facility that have a fair value asset of approximately $0.1 million.

At June 30, 2011, 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, 2011, we recorded an unrealized gain of $1.8 million related to the basis swaps that did not qualify for hedge accounting treatment and an unrealized gain of $2.1 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, 2010, we had outstanding natural gas price swaps on total notional volumes of 66.8 Bcf in 2011, 68.1 Bcf in 2012 and 36.5 in 2013 for which we will receive fixed prices ranging from $5.00 to $7.03 per MMBtu. At December 31, 2010, we had collars in place on notional volumes of 62.1 Bcf in 2011 at an average floor and ceiling price of $5.09 and $6.50 per MMBtu, respectively, and collars on notional volumes of 80.5 Bcf in 2012 at an average floor and ceiling price of $5.50 and $6.67 per MMBtu, respectively.

Additionally, at December 31, 2010, we had outstanding fixed price basis differential swaps on 12.0 Bcf of 2011 natural gas production that did not qualify for hedge treatment.

Midstream Services

At June 30, 2011, our Midstream Services segment had outstanding fair value hedges in place on 0.1 Bcf and 0.1 Bcf of natural gas for 2011 and 2012, respectively. These hedges are a mixture of floating-price swap purchases and sales relating to our gas marketing activities. These hedges have contract months from October 2011 and March 2012 and have a net fair value liability of $0.4 million as of June 30, 2011.

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, 2011. There were no changes in our internal control over financial reporting during the three months ended June 30, 2011 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 laws and regulations relating to the protection of the environment. Our 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 our financial position, results of operations, and cash flows.

In February 2009, SEPCO was added as a defendant in a Third Amended Petition in the matter of Tovah Energy, LLC and Toby Berry-Helfand v. David Michael Grimes, et, al. In the Sixth Amended Petition, filed in July 2010, in the 273 rd District Court in Shelby County, Texas (collectively, the "Sixth Petition") plaintiff alleged that, in 2005, they provided SEPCO with proprietary data regarding two prospects in the James Lime formation pursuant to a confidentiality agreement and that SEPCO refused to return the proprietary data to the plaintiff, subsequently acquired leases based upon such proprietary data and profited therefrom. Among other things, the plaintiff's allegations in the Sixth Petition included various statutory and common law claims, including, but not limited to claims of misappropriation of trade secrets, violation of the Texas Theft Liability Act, breach of fiduciary duty and confidential relationships, various fraud based claims and breach of contract, including a claim of breach of a purported right of first refusal on all interests acquired by SEPCO between February 15, 2005 and February 15, 2006. In the Sixth Petition, plaintiff sought actual damages of over $55 million as well as other remedies, including special damages and punitive damages of four times the amount of actual damages established at trial.

Immediately before the commencement of the trial in November 2010, plaintiff was permitted, over SEPCO's objections, to file a Seventh Amended Petition claiming actual damages of $46 million and also seeking the equitable remedy of disgorgement of all profits for the misappropriation of trade secrets and the breach of fiduciary duty claims. In December 2010, the jury found in favor of the plaintiff with respect to all of the statutory and common law claims and awarded $11.4 million in compensatory damages. The jury did not, however, award the plaintiff any special, punitive or other damages. In addition, the jury separately determined that SEPCO's profits for purposes of disgorgement were $381.5 million. This profit determination does not constitute a judgment or an award. The plaintiff's entitlement to disgorgement of profits as an equitable remedy will be determined by the judge and it is within the judge's discretion to award none, some or all the amount of profit to the plaintiff. On December 31, 2010, the plaintiff filed a motion to enter the judgment based on the jury's verdict. On February 11, 2011, SEPCO filed a motion for a judgment notwithstanding the verdict and a motion to disregard certain findings. On March 11, 2011, the plaintiff filed an amended motion for judgment and intervenor filed its motion for judgment seeking not only the monetary damages and the profits determined by the jury but also seeking, as a new remedy, a constructive trust for profits from 143 wells as well as future drilling and sales of properties in the prospect areas. A hearing on the post-verdict motions was held on March 14, 2011. At the suggestion of the judge, all parties voluntarily agreed to participate in non-binding mediation efforts. The mediation occurred on April 6, 2011 and was unsuccessful. On June 6, 2011, SEPCO received by mail a letter dated June 2, 2011 from the judge, in which he made certain rulings with respect to the post-verdict motions and responses filed by the parties. In his rulings, the judge denied SEPCO's motion for judgment, judgment notwithstanding the verdict and to disregard certain findings. Plaintiff's and intervenor's claim for a constructive trust was denied but the judge ruled that plaintiff and intervenor shall recover from SEPCO $11.4 million and a reasonable attorney's fee of 40% of the total damages awarded and are entitled to recover on their claim for disgorgement. The judge instructed that SEPCO calculate the profit on the designated wells for each respective period. SEPCO performed the calculation and provided it to the judge in June 2011. On July 5, 2011, plaintiff and intervenor filed a letter with the court raising objections to the accounting provided by SEPCO, to which SEPCO filed a response on July 11, 2011. On July 12, 2011, the judge sent a letter to the parties in which he ruled that after reviewing the parties' respective position letters, he was awarding $23.9 million in disgorgement damages in favor of the plaintiff and intervenor. In the July 12, 2011 letter, the judge instructed the plaintiff and intervenor to prepare a judgment for his approval prior to July 21, 2011 consistent with his findings in his June 2, 2011 letter and the disgorgement award. Plaintiff and intervenor have not complied with the court's instructions as of the date hereof and, on July 14, 2011, requested an oral hearing, to which SEPCO filed its objections on July 18, 2011. SEPCO does not believe that the foregoing rulings by the judge constitute the entry of a judgment at this time. However, the Company currently expects that the entry of a judgment against SEPCO will be consistent with these rulings, and therefore will be adverse.

If an adverse judgment is entered against SEPCO, the Company believes that SEPCO has a number of legal grounds for appealing the judgment, all of which will be vigorously pursued. Based on the Company's understanding and judgment of the facts and merits of this case, including appellate defenses, and after considering the advice of counsel, the Company has determined that, although reasonably possible after exhaustion of all appeals, an adverse final outcome to this lawsuit is not probable. As such, the Company has not accrued any amounts with respect to this lawsuit. If the plaintiff and intervenor were to ultimately prevail in the appellate process, the Company currently estimates, based on the judge's rulings to date, that SEPCO's potential liability would be in the range of zero to $35.3 million, excluding interest and attorney's fees. The Company's assessment may change in the future due to occurrence of certain events, such as denied appeals, and such re-assessment could lead to the determination that the potential liability is probable and could be material to the Company's results of operations, financial position or cash flows.

In March 2010, the Company's subsidiary, SEECO, Inc., was served with a subpoena from a federal grand jury in Little Rock, Arkansas. Based on the documents requested under the subpoena and subsequent discussions described below, the Company believes the grand jury is investigating matters involving approximately 27 horizontal wells operated by SEECO in Arkansas, including whether appropriate leases or permits were obtained therefor and whether royalties and other production attributable to federal lands have been properly accounted for and paid. The Company believes it has fully complied with all requests related to the federal subpoena and delivered its affidavit to that effect. The Company and representatives of the Bureau of Land Management and the U.S. Attorney have had discussions since the production of the documents pursuant to the subpoena. In January 2011, the Company voluntarily produced additional materials informally requested by the government arising from these discussions. Although, to the Company's knowledge, no proceeding in this matter has been initiated against SEECO, the Company cannot predict whether or when one might be initiated. The Company intends to fully comply with any further requests and to cooperate with any related investigation. No assurance can be made as to the time or resources that will need to be devoted to this inquiry or the impact of the final outcome of the discussions or any related proceeding.

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

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 2010 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.

(31.1)	Certification of CEO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(31.2)	Certification of CFO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(32.1)	Certification of CEO and CFO furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(101.INS)	Interactive Data File Instance Document
(101.SCH)	Interactive Data File Schema Document
(101.CAL)	Interactive Data File Calculation Linkbase Document
(101.LAB)	Interactive Data File Label Linkbase Document
(101.PRE)	Interactive Data File Presentation Linkbase Document
(101.DEF)	Interactive Data File Definition Linkbase Document

Signatures

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

SOUTHWESTERN ENERGY COMPANY
Registrant

Dated: July 28, 2011

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