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

Form 10-Q

(Mark One)
[X] Quarterly Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended **September 30, 2012**

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 October 26, 2012
Common Stock, Par Value $0.01	350,353,301

SOUTHWESTERN ENERGY COMPANY

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FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2012

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 play and Marcellus Shale play;
- 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 forward-looking statements contained in this Form 10-Q are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of natural gas and oil. These risks include, but are not limited to, commodity price volatility, third-party interruption of sales to market, inflation, lack of availability of goods and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating proved natural gas and oil reserves and in projecting future rates of production and timing of development expenditures and the other risks described in our Annual Report on Form 10-K for the year ended December 31, 2011 (the "2011 Annual Report on Form 10-K"), and all quarterly reports on Form 10-Q filed subsequently thereto, including this Form 10-Q ("Form 10-Qs").

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

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

PART I – FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS.

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

	For the three months ended September 30,		For the nine months ended September 30,	
	2012	2011	2012	2011
	(in thousands, except share/per share amounts)			
Operating Revenues:				
Gas sales	$ 491,340	$ 551,770	$ 1,384,152	$ 1,544,165
Gas marketing	148,764	176,787	423,503	549,243
Oil sales	1,889	2,157	6,097	7,387
Gas gathering	43,855	36,541	128,293	107,961
	685,848	767,255	1,942,045	2,208,756
Operating Costs and Expenses:				
Gas purchases – midstream services	149,651	175,236	423,941	545,518
Operating expenses	61,906	63,911	179,478	175,763
General and administrative expenses	36,121	35,600	129,879	112,955
Depreciation, depletion and amortization	200,655	179,113	602,112	514,180
Impairment of natural gas and oil properties	441,465	–	1,377,364	–
Taxes, other than income taxes	16,252	17,677	51,154	49,429
	906,050	471,537	2,763,928	1,397,845
Operating Income (Loss)	(220,202)	295,718	(821,883)	810,911
Interest Expense:				
Interest on debt	25,463	16,696	69,154	48,380
Other interest charges	1,058	902	3,096	3,414
Interest capitalized	(15,915)	(11,941)	(45,945)	(32,531)
	10,606	5,657	26,305	19,263
Other Income (Loss), Net	238	(122)	2,615	321
Income (Loss) Before Income Taxes	(230,570)	289,939	(845,573)	791,969
Provision (Benefit) for Income Taxes:				
Current	101	3,491	369	3,691
Deferred	(85,856)	111,275	(320,731)	309,042
	(85,755)	114,766	(320,362)	312,733
Net Income (Loss)	$ (144,815)	$ 175,173	$ (525,211)	$ 479,236
Earnings (Loss) Per Share:				
Basic	$ (0.42)	$ 0.50	$ (1.51)	$ 1.38
Diluted	$ (0.42)	$ 0.50	$ (1.51)	$ 1.37
Weighted Average Common Shares Outstanding:				
Basic	348,649,630	347,239,793	348,272,192	347,070,330
Diluted	348,649,630	349,998,789	348,272,192	349,891,885

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(Unaudited)

	For the three months ended September 30,		For the nine months ended September 30,	
	2012	2011	2012	2011
	(in thousands)			
Net income (loss)	$ (144,815)	$ 175,173	$ (525,211)	$ 479,236
Change in derivatives:				
Reclassification to earnings (1)	(94,996)	(49,436)	(310,882)	(113,850)
Ineffectiveness (2)	322	1,574	(1,215)	307
Change in fair value of derivative instruments (3)	(36,468)	170,251	93,985	259,559
Total change in derivatives	(131,142)	122,389	(218,112)	146,016
Change in value of pension and other postretirement liabilities:				
Amortization of prior service cost included in net periodic pension cost (4)	254	197	762	590
Change in currency translation adjustment	997	(1,219)	962	(831)
Comprehensive income (loss)	$ (274,706)	$ 296,540	$ (741,599)	$ 625,011

(1) Net of $(62.2), $(31.6), $(202.6) and $(72.8) million in taxes for the three months ended September 30, 2012 and 2011, and the nine months ended September 30, 2012 and 2011, respectively.

(2) Net of $0.2, $1.0, $(0.8) and $0.2 million in taxes for the three months ended September 30, 2012 and 2011, and the nine months ended September 30, 2012 and 2011, respectively.

(3) Net of $ (22.1), $108.8, $62.7 and $165.9 million in taxes for the three months ended September 30, 2012 and 2011, and the nine months ended September 30, 2012 and 2011, respectively.

(4) Net of $0.2,$0.2, $0.5 and $0.4 million in taxes for the three months ended September 30, 2012 and 2011, and the nine months ended September 30, 2012 and 2011, respectively.

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

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

	September 30, 2012	December 31, 2011
ASSETS	(in thousands)	
Current assets:		
Cash and cash equivalents	$ 18,560	$ 15,627
Restricted cash	127,074	–
Accounts receivable	297,773	341,915
Inventories	30,630	46,234
Hedging asset	300,861	514,465
Other	71,849	60,037
Total current assets	846,747	978,278
Natural gas and oil properties, using the full cost method, including $1,130.4 million in 2012 and $942.9 million in 2011 excluded from amortization	10,855,274	9,544,708
Gathering systems	1,087,139	980,647
Other	564,490	535,464
Less: Accumulated depreciation, depletion and amortization	(6,414,955)	(4,415,339)
Total property and equipment, net	6,091,948	6,645,480
Other assets	134,256	279,139
TOTAL ASSETS	$ 7,072,951	$ 7,902,897
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 468,646	$ 514,071
Taxes payable	36,902	40,691
Interest payable	14,232	20,565
Advances from partners	110,237	84,082
Current deferred income taxes	116,463	194,163
Other	14,685	31,341
Total current liabilities	761,165	884,913
Long-term debt	1,695,342	1,342,100
Deferred income taxes	1,203,703	1,586,798
Pension and other postretirement liabilities	18,141	20,338
Other long-term liabilities	141,321	99,444
Total long-term liabilities	3,058,507	3,048,680
Commitments and contingencies (Note 10)		
Equity:		
Common stock, $0.01 par value; authorized 1,250,000,000 shares; issued 350,415,917 shares in 2012 and 349,058,501 in 2011	3,504	3,491
Additional paid-in capital	928,322	903,399
Retained earnings	2,131,003	2,656,214
Accumulated other comprehensive income	192,040	408,428
Common stock in treasury, 66,791 shares in 2012 and 98,889 in 2011	(1,590)	(2,228)
Total equity	3,253,279	3,969,304
TOTAL LIABILITIES AND EQUITY	$ 7,072,951	$ 7,902,897

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

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

	For the nine months ended September 30, 2012	2011
	(in thousands)	
Cash Flows From Operating Activities		
Net income (loss)	$ (525,211)	$ 479,236
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	604,887	516,891
Impairment of natural gas and oil properties	1,377,364	–
Deferred income taxes	(320,731)	309,042
Unrealized gain on derivatives	(2,890)	905
Stock-based compensation	8,226	6,619
Other	312	(353)
Change in assets and liabilities:		
Accounts receivable	44,148	4,664
Inventories	16,608	(5,993)
Accounts payable	(11,050)	1,539
Taxes payable	(3,789)	(21,165)
Interest payable	(2,306)	(9,365)
Advances from partners	26,155	14,568
Other assets and liabilities	(19,246)	3,623
Net cash provided by operating activities	1,192,477	1,300,211
Cash Flows From Investing Activities		
Capital investments	(1,623,751)	(1,543,549)
Proceeds from sale of property and equipment	201,161	121,546
Transfers to restricted cash	(167,774)	(85,040)
Transfers from restricted cash	40,700	15,779
Other	5,239	4,940
Net cash used in investing activities	(1,544,425)	(1,486,324)
Cash Flows From Financing Activities		
Payments on current portion of long-term debt	(600)	(600)
Payments on revolving long-term debt	(1,774,000)	(2,575,000)
Borrowings under revolving long-term debt	1,129,000	2,753,600
Change in bank drafts outstanding	1,627	10,621
Proceeds from issuance of long-term debt	998,780	–
Debt issuance costs	(8,338)	–
Revolving credit facility costs	–	(10,211)
Proceeds from exercise of common stock options	8,422	4,844
Net cash provided by financing activities	354,891	183,254
Effect of exchange rate changes on cash	(10)	97
Increase (decrease) in cash and cash equivalents	2,933	(2,762)
Cash and cash equivalents at beginning of year	15,627	16,055
Cash and cash equivalents at end of period	$ 18,560	$ 13,293

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 Shares Issued	Common Stock Amount	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Common Stock in Treasury	Total
	(in thousands)						
Balance at December 31, 2011	349,059	$ 3,491	$ 903,399	$ 2,656,214	$ 408,428	$ (2,228)	$ 3,969,304
Comprehensive loss:							
Net loss	–	–	–	(525,211)	–	–	(525,211)
Other comprehensive loss	–	–	–	–	(216,388)	–	(216,388)
Total comprehensive loss	–	–	–	–	–	–	(741,599)
Stock-based compensation	–	–	16,014	–	–	–	16,014
Exercise of stock options	1,422	14	8,408	–	–	–	8,422
Issuance of restricted stock	12	–	–	–	–	–	–
Cancellation of restricted stock	(77)	(1)	1	–	–	–	–
Treasury stock – non-qualified plan	–	–	500	–	–	638	1,138
Balance at September 30, 2012	350,416	$ 3,504	$ 928,322	$ 2,131,003	$ 192,040	$ (1,590)	$ 3,253,279

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, “we”, “Southwestern” or the “Company”) is an independent energy company engaged in natural gas and oil exploration, development and production. The Company engages in natural gas and oil exploration and production, natural gas gathering and natural gas marketing through its subsidiaries. Southwestern’s exploration, development and production (“E&P”) activities are principally focused within the United States on development of an unconventional gas reservoir located on the Arkansas side of the Arkoma Basin, which the Company refers to as the Fayetteville Shale play. The Company is actively engaged in exploration and production activities in Pennsylvania, where we are targeting the unconventional gas reservoir known as the Marcellus Shale, and to a lesser extent in Texas and in Arkansas and Oklahoma in the Arkoma Basin. The Company also actively seeks to find and develop new oil and natural gas plays with significant exploration and exploitation potential. Southwestern’s natural gas gathering and marketing (“Midstream Services”) activities primarily support the Company’s E&P activities in Arkansas, Pennsylvania and Texas.

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, 2011 (“2011 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 2011 Annual Report on Form 10-K. The Company evaluates subsequent events through the date the financial statements are issued.

Certain reclassifications have been made to the prior year financial statements to conform to the 2012 presentation. The effects of the reclassifications were not material to the Company’s unaudited condensed consolidated financial statements.

In the third quarter of 2012, the Company recorded a correction to increase the asset retirement obligation by approximately $39 million. Because the amounts involved were not material to the Company’s financial statements in any individual prior period and the cumulative amount is not material to the current period financial statements, the Company recorded the cumulative effect of correcting this error during the quarter ended September 30, 2012.

(2) DIVESTITURES

In May 2012, we sold certain oil and natural gas leases, wells and gathering equipment in East Texas for approximately $168.0 million, excluding typical purchase price adjustments. The proceeds were deposited with a qualified intermediary to facilitate potential like-kind exchange transactions pursuant to Section 1031 of the Internal Revenue Code and, unless utilized for one or more like-kind exchange transactions, were restricted in their use until October 2012. The assets included in the sale represented all of the Company’s interests and related assets in the Overton Field in Smith County. The net production from the sold assets was approximately 24.0 MMcfe per day as of the closing date and our net proved reserves were approximately 143.0 Bcfe at December 31, 2011.

In May 2011, we sold certain oil and natural gas leases, wells and gathering equipment in East Texas for approximately $118.1 million. The sale included only the producing rights to the Haynesville and Middle Bossier Shale intervals in approximately 9,717 net acres. The net production from the Haynesville and Middle Bossier Shale intervals in this acreage was approximately 7.0 MMcf per day and proved net reserves were approximately 37.1 Bcf when the sale was closed in May 2011.

(3) PREPAID EXPENSES

The components of prepaid expenses included in other current assets as of September 30, 2012 and December 31, 2011 consisted of the following:

	September 30, 2012	December 31, 2011
	(in thousands)	
Prepaid drilling costs	$ 47,462	$ 42,775
Prepaid insurance	11,944	7,275
Total	$ 59,406	$ 50,050

(4) INVENTORY

Inventory recorded in current assets includes $6.2 million at September 30, 2012 and $7.8 million at December 31, 2011 for natural gas in underground storage owned by the Company's E&P segment, and $24.4 million at September 30, 2012 and $38.4 million at December 31, 2011 for tubular and other equipment used in the E&P segment.

Other Assets include $17.8 million at September 30, 2012 and $19.5 million December 31, 2011, respectively, for inventory held by the Midstream Services segment consisting primarily of pipe that will be used to construct gathering systems for the Fayetteville Shale play.

(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, net of taxes, discounted at 10 percent plus the lower of cost or market value of unproved properties. Any costs in excess of the ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, even though higher natural gas and oil prices may subsequently increase the ceiling. Full cost companies must use the average quoted price from the first day of each month from the previous 12 months, including the impact of derivatives qualifying as cash flow hedges, to calculate the ceiling value of their reserves.

Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $2.83 per MMBtu and $91.48 per barrel for West Texas Intermediate oil, adjusted for market differentials, the Company's net book value of its United States natural gas and oil properties exceeded the ceiling by approximately $276.6 million (net of tax) at September 30, 2012 and resulted in a non-cash ceiling test impairment. Cash flow hedges of natural gas production in place increased the ceiling by $330.6 million at September 30, 2012. In the second quarter of 2012, the Company's net book value of its United States natural gas and oil properties exceeded the ceiling by approximately $578.9 million (net of tax) at June 30, 2012 and resulted in a non-cash ceiling test impairment. Decreases in average quoted prices from September 30, 2012 levels as well as changes in production rates, levels of reserves, capitalized costs, the evaluation of costs excluded from amortization, future development costs, service costs and taxes could result in future ceiling test impairments.

All of the Company's costs directly associated with the acquisition and evaluation of properties in New Brunswick, Canada relating to its exploration program at September 30, 2012 were unproved and did not exceed the ceiling amount. If the 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 nine-month periods ended September 30, 2012 and 2011:

	For the three months ended September 30, 2012	For the three months ended September 30, 2011	For the nine months ended September 30, 2012	For the nine months ended September 30, 2011
Net income (loss) (in thousands)	$ (144,815)	$ 175,173	$ (525,211)	$ 479,236
Number of common shares:				
Weighted average outstanding	348,649,630	347,239,793	348,272,192	347,070,330
Issued upon assumed exercise of outstanding stock options	–	2,490,783	–	2,591,687
Effect of issuance of nonvested restricted common stock	–	268,213	–	229,868
Weighted average and potential dilutive outstanding(1)	348,649,630	349,998,789	348,272,192	349,891,885
Earnings (loss) per share:				
Basic	$ (0.42)	$ 0.50	$ (1.51)	$ 1.38
Diluted	$ (0.42)	$ 0.50	$ (1.51)	$ 1.37

(1) As we recognized a net loss for the three- and nine-months ended September 30, 2012, the unvested share-based payments and stock options were not recognized in diluted earnings per share ("Diluted EPS") calculations as they would be antidilutive. Options for 1,664,232 shares and 560,848 shares of restricted stock were excluded from the calculation for the three months ended September 30, 2012 because they would have had an antidilutive effect. Options for 783,823 shares and 5,645 shares of restricted stock were excluded from the calculation for the three months ended September 30, 2011 because they would have had an antidilutive effect. Options for 1,685,398 shares and 580,227 shares of restricted stock were excluded from the calculation for the nine months ended September 30, 2012 because they would have had an antidilutive effect. Options for 811,552 shares and 7,114 shares of restricted stock were excluded from the calculation for the nine months ended September 30, 2011 because they would have had an antidilutive effect.

(7) DERIVATIVES AND RISK MANAGEMENT

The Company is exposed to volatility in market prices and basis differentials for natural gas and crude oil which impacts the predictability of its cash flows related to the sale of natural gas and oil. These risks are managed by the Company's use of certain derivative financial instruments. At September 30, 2012 and December 31, 2011, 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 assets related to derivative financial instruments are summarized below at September 30, 2012 and December 31, 2011:

	Derivative Assets			
	September 30, 2012		December 31, 2011	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Derivatives designated as hedging instruments:				
Fixed and floating price swaps	Hedging asset	$ 254,358	Hedging asset	$ 333,479
Costless-collars	Hedging asset	43,984	Hedging asset	179,080
Fixed and floating price swaps	Other assets	48,252	Other assets	201,081
Total derivatives designated as hedging instruments		$ 346,594		$ 713,640
Derivatives not designated as hedging instruments:				
Basis swaps	Hedging asset	$ 2,519	Hedging asset	$ 1,906
Basis swaps	Other assets	696	Other assets	1,797
Total derivatives not designated as hedging instruments		$ 3,215		$ 3,703
Total derivative assets		$ 349,809		$ 717,343

	Derivative Liabilities			
	September 30, 2012		December 31, 2011	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Derivatives designated as hedging instruments:				
Fixed and floating price swaps	Other current liabilities	$ 1,818	Other current liabilities	$ 11,849
Costless-collars	Other current liabilities	–	Other current liabilities	209
Total derivatives designated as hedging instruments		$ 1,818		$ 12,058
Derivatives not designated as hedging instruments:				
Basis swaps	Other current liabilities	$ 223	Other current liabilities	$ 400
Basis swaps	Other long-term liabilities	15	Other long-term liabilities	55
Total derivatives not designated as hedging instruments		$ 238		$ 455
Total derivative liabilities		$ 2,056		$ 12,513

Cash Flow Hedges

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

As of September 30, 2012, the Company had cash flow hedges on the following volumes of natural gas production (in Bcf):

Year	Fixed price swaps	Costless-collars
2012	46.7	20.2
2013	185.6	–

As of September 30, 2012, the Company recorded a net gain in accumulated other comprehensive income related to its hedging activities of $206.7 million. This amount is net of a deferred income tax liability recorded as of September 30, 2012 of $135.6 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 September 30, 2012 remain unchanged, the Company would expect to transfer an aggregate after-tax net gain of $177.9 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. 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 nine-month periods ended September 30, 2012 and 2011:

	Gain (Loss) Recognized in Other Comprehensive Income (Effective Portion)			
	For the three months ended September 30,		For the nine months ended September 30,	
Derivative Instrument	2012	2011	2012	2011
	(in thousands)			
Fixed price swaps	$ (55,039)	$ 230,783	$ 116,089	$ 360,362
Costless-collars	$ (3,497)	$ 48,315	$ 40,644	$ 65,144

	Classification of Gain Reclassified from Accumulated Other Comprehensive Income into Earnings (Effective Portion)	Gain Reclassified from Accumulated Other Comprehensive Income into Earnings (Effective Portion)			
		For the three months ended September 30,		For the nine months ended September 30,	
Derivative Instrument		2012	2011	2012	2011
		(in thousands)			
Fixed price swaps	Gas Sales	$ 102,789	$ 67,125	$ 337,994	$ 145,662
Costless-collars	Gas Sales	$ 54,489	$ 13,918	$ 175,531	$ 40,978

	Classification of Gain (Loss) Recognized in Earnings (Ineffective Portion)	Gain (Loss) Recognized in Earnings (Ineffective Portion)			
		For the three months ended September 30,		For the nine months ended September 30,	
Derivative Instrument		2012	2011	2012	2011
		(in thousands)			
Fixed price swaps	Gas Sales	$ (165)	$ (1,754)	$ 1,831	$ (755)
Costless-collars	Gas Sales	$ (373)	$ (826)	$ 167	$ 252

Fair Value Hedges

For fair value hedges, the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item are recognized in earnings immediately. As of September 30, 2012 and December 31, 2011, 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 other current 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 September 30, 2012, the Company had basis swaps on natural gas production that did not qualify for hedge accounting treatment of 9.2 Bcf, 30.1 Bcf and 9.1 Bcf in 2012, 2013, and 2014, 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 nine-month periods ended September 30, 2012 and 2011:

		Unrealized Loss Recognized in Earnings			
	Income Statement Classification	For the three months ended September 30,		For the nine months ended September 30,	
Derivative Instrument	of Unrealized Loss	2012	2011	2012	2011
		(in thousands)			
Basis swaps	Gas Sales	$ (1,275)	$ (1,967)	$ (270)	$ (159)

		Realized Gain (Loss) Recognized in Earnings			
	Income Statement Classification	For the three months ended September 30,		For the nine months ended September 30,	
Derivative Instrument	of Realized Gain (Loss)	2012	2011	2012	2011
		(in thousands)			
Basis swaps	Gas Sales	$ 624	$ (22)	$ 1,773	$ (2,377)

(8) FAIR VALUE MEASUREMENTS

The carrying amounts and estimated fair values of the Company's financial instruments as of September 30, 2012 and December 31, 2011 were as follows:

	September 30, 2012		December 31, 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Cash and cash equivalents	$ 18,560	$ 18,560	$ 15,627	$ 15,627
Restricted cash	$ 127,074	$ 127,074	$ –	$ –
Unsecured revolving credit facility	$ 26,500	$ 26,500	$ 671,500	$ 671,500
Senior notes	$ 1,670,042	$ 1,878,983	$ 671,800	$ 773,578
Derivative instruments	$ 347,753	$ 347,753	$ 704,830	$ 704,830

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 3.1% at September 30, 2012 and 4.6% at December 31, 2011, and its 4.10% Senior Notes due 2022, which was 3.4% at September 30, 2012. The carrying value of the borrowings under the Company's unsecured revolving credit facility at September 30, 2012 and December 31, 2011, approximate fair value because the interest rate is variable and reflective of market rates. As such, the Company considers the fair value of its debt to be a Level 2 measurement on the fair value hierarchy.

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.

The accounting group, reporting to the Vice President and Controller, is responsible for determining the Company's Level 3 fair value measurements. Inputs to the Black-Scholes model, including the volatility input, which is the significant unobservable input for Level 3 fair value measurements, are obtained from a third-party pricing source, with independent verification of most significant inputs on a monthly basis. An increase (decrease) in volatility would result in an increase (decrease) in fair value measurement, respectively.

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

	September 30, 2012			
	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	$ –	$ 302,610	$ 47,199	$ 349,809
Derivative liabilities	–	(1,818)	(238)	(2,056)
Total	$ –	$ 300,792	$ 46,961	$ 347,753

	December 31, 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	$ –	$ 534,560	$ 182,783	$ 717,343
Derivative liabilities	–	(11,849)	(664)	(12,513)
Total	$ –	$ 522,711	$ 182,119	$ 704,830

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 nine-month periods ended September 30, 2012 and September 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 reasonable marketplace participant would have used at September 30, 2012 and September 30, 2011.

	For the three months ended September 30,		For the nine months ended September 30,	
	2012	2011	2012	2011
	(in thousands)			
Balance at beginning of period	$ 106,222	$ 89,395	$ 182,119	$ 97,677
Total gains or losses (realized/unrealized):				
Included in earnings	53,465	11,102	177,201	38,694
Included in other comprehensive income	(57,614)	35,223	(135,055)	23,913
Purchases, issuances, and settlements:				
Purchases	–	–	–	–
Issuances	–	–	–	–
Settlements	(55,112)	(13,895)	(177,304)	(38,601)
Transfers into/out of Level 3	–	–	–	142
Balance at end of period	$ 46,961	$ 121,825	$ 46,961	$ 121,825
Change in unrealized gains included in earnings relating to derivatives still held as of September 30	$ (1,647)	$ (2,793)	$ (103)	$ 93

(9) DEBT

The components of debt as of September 30, 2012 and December 31, 2011 consisted of the following:

	September 30, 2012	December 31, 2011
	(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 (2.200% and 2.276% at September 30, 2012 and December 31, 2011, respectively) unsecured revolving credit facility, expires February 2016	26,500	671,500
7.5% Senior Notes due 2018	600,000	600,000
7.35% Senior Notes due 2017	15,000	15,000
7.125% Senior Notes due 2017	25,000	25,000
7.15% Senior Notes due 2018	30,000	30,600
4.10% Senior Notes due 2022	1,000,000	–
Unamortized discount	(1,158)	–
Total long-term debt	1,695,342	1,342,100
Total debt	$ 1,696,542	$ 1,343,300

Issuance of 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"). If no default or event of default has occurred and is continuing, these guarantees will be released (i) automatically upon any sale, exchange, or transfer of all of the Company's equity interests in the guarantor; (ii) automatically upon the liquidation and dissolution of a guarantor; (iii) following delivery of notice to the trustee of the release of the guarantor of its obligations under the Company's credit facility; and (iv) upon legal or covenant defeasance or other satisfaction of the obligations under the notes.

Please refer to Note 16, "Condensed Consolidating Financial Information" in this Form 10-Q for additional information.

In March 2012, the Company issued $1.0 billion of 4.10% Senior Notes due 2022 in a private placement. The 4.10% Senior Notes are redeemable at the Company's election, in whole or in part, at any time prior to December 15, 2021, at a redemption price equal to the greater of: (1) 100% of the principal amount of the notes to be redeemed then outstanding; and (2) the sum of the present values of the remaining scheduled payments of principal and interest on the notes to be redeemed (not including any portion of such payments of interest accrued to the date of redemption) discounted to the redemption date on a semiannual basis (assuming a 360-day year consisting of twelve 30-day months) as determined in accordance with the Indenture, plus 35 basis points, plus, in either of such cases, accrued and unpaid interest to the date of redemption on the notes to be redeemed. In addition, if the Company undergoes a "change of control," as defined in the indenture, holders of the 4.10% Senior Notes will have the option to require the Company to purchase all or any portion of the notes at a purchase price equal to 101% of the principal amount of the notes to be purchased plus any accrued and unpaid interest to, but excluding, the change of control date. Payment obligations with respect to the 4.10% Senior Notes are currently guaranteed by the Company's subsidiaries, SEECO, SEPCO and SES, which guarantees may be unconditionally released in certain circumstances. The Company has agreed to cause to become effective a registration statement with respect to an offer to exchange the 4.10% Senior Notes and related guarantees for freely tradeable notes with identical terms and related guarantees on or prior to the 270th calendar day after issuance and to cause a shelf registration statement to become effective for resales if requested by the initial purchasers of the Notes. The Company will be obligated to pay additional interest if the exchange offer is not completed or the shelf registration statement, if required, is not effective, on or before the 330th day after issuance. The indentures governing the 4.10% Senior Notes and the Company's other senior notes contain covenants that, among other things, restrict the ability of the Company and/or its subsidiaries to incur liens, to engage in sale and leaseback transactions and to merge, consolidate or sell assets.

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 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 September 30, 2012. The Credit Facility is guaranteed by the Company's subsidiary, SEECO and requires additional subsidiary guarantors if certain guaranty coverage levels are not satisfied. The 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 adjusted 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. As of September 30, 2012, the Company 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

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 $47.0 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 no liability has been recognized in connection with the promissory notes due to the Company's investments in New Brunswick as of September 30, 2012 and its future investment plans.

On March 23, 2012, SES entered into a precedent agreement with Constitution Pipeline Co. LLC for a proposed 121-mile pipeline connecting to the Iroquois Gas Transmission and Tennessee Gas Pipeline systems in Schoharie County, New York. Subject to the receipt of regulatory approvals and satisfaction of other conditions, SES has agreed to enter a fifteen year firm transportation agreement with a total capacity of 150 MMcf per day. The project is expected to be in service by the second quarter of 2015.

SES and SEPCO have 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. As of September 30, 2012, the aggregate obligations under such gathering and firm transportation agreements (including precedent agreements assuming completion of the pipeline projects) for the Marcellus Shale operations totaled approximately $1.3 billion and the Company has guarantee obligations of up to $100.0 million of that amount.

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 273rd 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 $55.0 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 $46.0 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. On August 24, 2011, a judgment was entered pursuant to which plaintiff and intervenor are entitled to recover approximately $11.4 million in actual damages and approximately $23.9 million in disgorgement as well as prejudgment interest and attorneys' fees which currently are estimated to be up to $8.9 million and all costs of court of the plaintiff and intervenor. On September 23, 2011, SEPCO filed a motion for a new trial and on November 18, 2011 filed a notice of appeal. On November 30, 2011, the court approved SEPCO's supersedeas bond in the amount of $14.1 million, which stays execution on the judgment pending appeal. The bond covers the $11.4 million judgment for actual damages, plus $1.3 million in pre-judgment interest, $1.3 million in post-judgment interest (estimating two years for the duration of appeal), and court costs. On April 17, 2012, SEPCO filed an unopposed motion for the appellate court's permission to extend the deadline for filing its appeal to May 23, 2012.

On June 22, 2012, SEPCO filed its appellate brief and, on June 25, 2012, plaintiff and intervenor filed a cross-appellate brief seeking limited remand to reassess the disgorgement determination. The parties are seeking a final extension of their deadlines to respond to the opposing party's brief. Thus, we expect that plaintiff and intervenor will file their response to SEPCO's appellate brief on November 7, 2012, and SEPCO will file its response to plaintiff and intervenor's cross-appellate brief on the same day. Oral arguments are expected to occur in spring 2013. 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 judgments to date, that SEPCO's potential liability would be up to $44.2 million, including 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.

On February 20, 2012, the Company became aware that SEPCO was named as a defendant in the matter of Gery Muncey v. Southwestern Energy Production Company, et al filed in the District Court of San Augustine County in Texas on January 31, 2012. The plaintiff in this case is also the intervenor in the Tovah Energy matter described above and alleges various claims including fraud, misappropriation and breach of fiduciary duty that are purported as independent of the claims alleged in the Tovah Energy matter but arise from the substantially same circumstances involved in the Tovah Energy matter. The plaintiff is seeking value for various royalty and override ownership interests in wells drilled, disgorgement of profits and punitive damages. SEPCO's motion for summary judgment was granted on July 9, 2012. On August 22, 2012, the court signed a final take-nothing judgment in SEPCO's favor. Muncey has not filed any post-judgment motions or a notice of appeal, and the deadlines for filing same have now passed. This matter has been resolved in SEPCO's favor and is now over.

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 therefore 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.

We are subject to various litigation, claims and proceedings that have arisen in the ordinary course of business. Management believes, individually or in aggregate, such litigation, claims and proceedings will not have a material adverse impact on our financial position, results of operations or cash flows but these matters are subject to inherent uncertainties and management's view may change in the future. If an unfavorable final outcome were to occur, there exists the possibility of a material impact on our financial position, results of operations or cash flows for the period in which the effect becomes reasonably estimable. We accrue for such items when a liability is both probable and the amount can be reasonably estimated.

(11) SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION

Supplemental disclosures of cash flow information:

	For the three months ended September 30, 2012	For the three months ended September 30, 2011	For the nine months ended September 30, 2012	For the nine months ended September 30, 2011
	(in thousands)			
Cash paid during the year for interest	$ 45,667	$ 25,897	$ 75,487	$ 57,745
Cash paid during the year for income taxes	400	3,391	468	20,391
Noncash property changes	(55,729)	(46,792)	(34,940)	16,078

(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 nine-month periods ended September 30, 2012 and 2011:

	Pension Benefits			
	For the three months ended September 30, 2012	For the three months ended September 30, 2011	For the nine months ended September 30, 2012	For the nine months ended September 30, 2011
	(in thousands)			
Service cost	$ 2,736	$ 2,330	$ 8,207	$ 6,992
Interest cost	1,013	918	3,038	2,753
Expected return on plan assets	(1,356)	(1,099)	(4,069)	(3,298)
Amortization of prior service cost	71	86	214	258
Amortization of net loss	305	214	915	642
Net periodic benefit cost	$ 2,769	$ 2,449	$ 8,305	$ 7,347

	Postretirement Benefits			
	For the three months ended September 30, 2012	For the three months ended September 30, 2011	For the nine months ended September 30, 2012	For the nine months ended September 30, 2011
	(in thousands)			
Service cost	$ 458	$ 338	$ 1,374	$ 1,015
Interest cost	100	63	299	189
Amortization of transition obligation	16	16	48	48
Amortization of prior service cost	4	4	11	11
Amortization of net loss	23	2	69	8
Net periodic benefit cost	$ 601	$ 423	$ 1,801	$ 1,271

As of September 30, 2012, the Company has contributed $11.0 million to the pension plans and $0.1 million to the postretirement benefit plan, with no further contributions planned in 2012.

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 66,791 shares at September 30, 2012 compared to 98,889 shares at December 31, 2011.

(13) STOCK-BASED COMPENSATION

The Company recognized the following amounts in employee stock-based compensation costs for the three and nine months ended September 30, 2012 and 2011:

	For the three months ended September 30,		For the nine months ended September 30,	
	2012	2011	2012	2011
	(in thousands)			
Stock-based compensation cost – expensed	$ 2,677	$ 1,933	$ 8,226	$ 6,619
Stock-based compensation cost – capitalized	$ 2,482	$ 2,188	$ 7,788	$ 6,003

As of September 30, 2012, there was $35.7 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 nine months of 2012 and provides information for options outstanding as of September 30, 2012:

	Number of Options	Weighted Average Exercise Price
Outstanding at December 31, 2011	4,741,732	$ 21.24
Granted	21,450	29.86
Exercised	(1,422,127)	5.92
Forfeited or expired	(70,025)	37.68
Outstanding at September 30, 2012	3,271,030	$ 27.61
Exercisable at September 30, 2012	2,115,987	$ 22.59

The following table summarizes restricted stock activity for the nine months ended September 30, 2012 and provides information for unvested shares as of September 30, 2012:

	Number of Shares	Weighted Average Grant Date Fair Value
Unvested shares at December 31, 2011	1,019,737	$ 36.71
Granted	13,254	30.20
Vested	(39,594)	39.63
Forfeited	(76,978)	37.08
Unvested shares at September 30, 2012	916,419	$ 36.46

(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 2011 Annual Report on Form 10-K. Management evaluates the performance of its segments based on operating income, defined as operating revenues less operating costs. 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 interest and other income (loss). The "Other" column includes items not related to the Company's reportable segments including real estate and corporate items.

	Exploration and Production	Midstream Services	Other	Total
	(in thousands)			
Three months ended September 30, 2012:				
Revenues from external customers	$ 493,204	$ 192,619	$ 25	$ 685,848
Intersegment revenues	(981)	409,720	824	409,563
Operating income (loss)(1)	(296,108)	75,488	418	(220,202)
Other income (loss), net	213	27	(2)	238
Depreciation, depletion and amortization expense	189,714	10,620	321	200,655
Impairment of natural gas and oil properties	441,465	–	–	441,465
Interest expense(2)	6,707	3,659	240	10,606
Provision (benefit) for income taxes(2)	(112,822)	27,006	61	(85,755)
Assets	5,570,444	1,158,638	343,869 (3)	7,072,951
Capital investments(4)	385,585	31,693	7,608	424,886
Three months ended September 30, 2011:				
Revenues from external customers	$ 553,913	$ 213,328	$ 14	$ 767,255
Intersegment revenues	1,707	530,503	818	533,028
Operating income(1)	228,476	66,837	405	295,718
Other income (loss), net	(17)	(109)	4	(122)
Depreciation, depletion and amortization expense	169,391	9,414	308	179,113
Interest expense(2)	2,003	3,654	–	5,657
Provision for income taxes(2)	89,811	24,791	164	114,766
Assets	5,827,527	1,116,333	270,247 (3)	7,214,107
Capital investments(4)	421,182	32,158	17,095	470,435

	Exploration and Production	Midstream Services	Other	Total
		(in thousands)		
Nine months ended September 30, 2012:				
Revenues from external customers	$ 1,390,156	$ 551,796	$ 93	$ 1,942,045
Intersegment revenues	(1,716)	1,085,392	2,459	1,086,135
Operating income (loss)(1)	(1,039,737)	216,598	1,256	(821,883)
Other income (loss), net	(34)	4	2,645	2,615
Depreciation, depletion and amortization expense	568,654	32,499	959	602,112
Impairment of natural gas and oil properties	1,377,364	–	–	1,377,364
Interest expense(2)	14,459	10,904	942	26,305
Provision (benefit) for income taxes(2)	(399,756)	78,268	1,126	(320,362)
Assets	5,570,444	1,158,638	343,869 (3)	7,072,951
Capital investments(4)	1,450,569	105,576	30,486	1,586,631
Nine months ended September 30, 2011:				
Revenues from external customers	$ 1,551,538	$ 657,204	$ 14	$ 2,208,756
Intersegment revenues	10,120	1,526,504	2,387	1,539,011
Operating income(1)	629,298	180,398	1,215	810,911
Other income (loss), net	332	(28)	17	321
Depreciation, depletion and amortization expense	486,130	27,170	880	514,180
Interest expense(2)	5,706	13,557	–	19,263
Provision for income taxes(2)	246,685	65,560	488	312,733
Assets	5,827,527	1,116,333	270,247 (3)	7,214,107
Capital investments(4)	1,365,434	137,998	53,506	1,556,938

(1) The operating loss for the E&P segment includes a $441.5 million and $1,377.4 million non-cash ceiling test impairment of our natural gas and oil properties for the three and nine-months ended September 30, 2012 respectively.
(2) Interest income, interest expense and the provision for income taxes by segment are allocated as they are incurred at the corporate level.
(3) Other assets represent corporate assets not allocated to segments and assets, including restricted cash and investments in cash equivalents, for non-reportable segments.
(4) Capital investments include decreases of $56.2 million and $60.9 million for the three-month periods ended September 30, 2012 and 2011, respectively, and decreases of $40.7 million and $3.0 million for the nine-month periods ended September 30, 2012 and 2011, respectively, relating to the change in accrued expenditures between periods.

Included in intersegment revenues of the Midstream Services segment are $332.1 million and $459.4 million for the three months ended September 30, 2012 and 2011, respectively, and $863.7 million and $1,327.3 million for the nine months ended September 30, 2012 and 2011, 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 September 30, 2012 and 2011, capital investments within the E&P segment include $2.2 million and $8.3 million, respectively, related to the Company's activities in Canada. For the nine months ended September 30, 2012 and 2011, capital investments within the E&P segment include $6.9 million and $16.1 million, respectively, related to the Company's activities in Canada. At September 30, 2012, E&P segment assets include $36.4 million and at September 30, 2011, assets include $25.6 million related to the Company's activities in Canada.

(15) NEW ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

In December 2011, the FASB issued guidance on offsetting assets and liabilities and disclosure requirements in Accounting Standards Update No. 2011-11, *Disclosures about Offsetting Assets and Liabilities* ("Update 2011-11"). Update 2011-11 requires that entities disclose both gross and net information about instruments and transactions eligible for offset in the statement of financial position as well as instruments and transactions subject to an agreement similar to a master netting agreement. In addition, the standard requires disclosure of collateral received and posted in connection with master netting agreements or similar arrangements. Update 2011-11 is effective for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. The implementation of the disclosure requirement is not expected to have a material impact on the Company's consolidated 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 September 30, 2012:					
Operating revenues	$ –	$ 642,082	$ 121,343	$ (77,577)	$ 685,848
Operating costs and expenses:					
Gas purchases – midstream services	–	149,765	–	(114)	149,651
Operating expenses	–	106,293	32,277	(76,664)	61,906
General and administrative expenses	–	30,818	6,102	(799)	36,121
Depreciation, depletion and amortization	–	189,777	10,878	–	200,655
Impairment of natural gas and oil properties	–	441,465	–	–	441,465
Taxes, other than income taxes	–	13,513	2,739	–	16,252
Total operating costs and expenses	–	931,631	51,996	(77,577)	906,050
Operating income (loss)	–	(289,549)	69,347	–	(220,202)
Other income, net	–	216	22	–	238
Equity in earnings of subsidiaries	(144,815)	–	–	144,815	–
Interest expense	–	7,200	3,406	–	10,606
Income (loss) before income taxes	(144,815)	(296,533)	65,963	144,815	(230,570)
Provision (benefit) for income taxes	–	(111,505)	25,750	–	(85,755)
Net income (loss)	(144,815)	(185,028)	40,213	144,815	(144,815)
Comprehensive income (loss)	$ (274,706)	$ (316,170)	$ 41,210	$ 274,960	$ (274,706)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
Three months ended September 30, 2011:					
Operating revenues	$ –	$ 730,826	$ 105,486	$ (69,057)	$ 767,255
Operating costs and expenses:					
Gas purchases – midstream services	–	175,729	–	(493)	175,236
Operating expenses	–	101,645	30,034	(67,768)	63,911
General and administrative expenses	–	34,030	2,366	(796)	35,600
Depreciation, depletion and amortization	–	169,446	9,667	–	179,113
Taxes, other than income taxes	–	13,731	3,946	–	17,677
Total operating costs and expenses	–	494,581	46,013	(69,057)	471,537
Operating income	–	236,245	59,473	–	295,718
Other loss, net	–	(16)	(106)	–	(122)
Equity in earnings of subsidiaries	175,173	–	–	(175,173)	–
Interest expense	–	2,376	3,281	–	5,657
Income (loss) before income taxes	175,173	233,853	56,086	(175,173)	289,939
Provision for income taxes	–	92,725	22,041	–	114,766
Net income (loss)	175,173	141,128	34,045	(175,173)	175,173
Comprehensive income (loss)	$ 296,540	$ 263,517	$ 32,826	$ (296,343)	$ 296,540

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

(Unaudited)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
Nine months ended September 30, 2012:					
Operating revenues	$ –	$ 1,814,001	$ 350,064	$ (222,020)	$ 1,942,045
Operating costs and expenses:					
Gas purchases – midstream services	–	424,425	–	(484)	423,941
Operating expenses	–	311,165	87,461	(219,148)	179,478
General and administrative expenses	–	111,567	20,700	(2,388)	129,879
Depreciation, depletion and amortization	–	568,859	33,253	–	602,112
Impairment of natural gas and oil properties	–	1,377,364	–	–	1,377,364
Taxes, other than income taxes	–	42,159	8,995	–	51,154
Total operating costs and expenses	–	2,835,539	150,409	(222,020)	2,763,928
Operating income (loss)	–	(1,021,538)	199,655	–	(821,883)
Other income (loss), net	–	(23)	2,638	–	2,615
Equity in earnings of subsidiaries	(525,211)	–	–	525,211	–
Interest expense	–	15,460	10,845	–	26,305
Income (loss) before income taxes	(525,211)	(1,037,021)	191,448	525,211	(845,573)
Provision (benefit) for income taxes	–	(395,112)	74,750	–	(320,362)
Net income (loss)	(525,211)	(641,909)	116,698	525,211	(525,211)
Comprehensive income (loss)	$ (741,599)	$ (860,021)	$ 117,660	$ 742,361	$ (741,599)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
Nine months ended September 30, 2011:					
Operating revenues	$ –	$ 2,101,099	$ 299,252	$ (191,595)	$ 2,208,756
Operating costs and expenses:					
Gas purchases – midstream services	–	546,731	–	(1,213)	545,518
Operating expenses	–	276,974	86,811	(188,022)	175,763
General and administrative expenses	–	101,372	13,943	(2,360)	112,955
Depreciation, depletion and amortization	–	485,546	28,634	–	514,180
Taxes, other than income taxes	–	41,206	8,223	–	49,429
Total operating costs and expenses	–	1,451,829	137,611	(191,595)	1,397,845
Operating income	–	649,270	161,641	–	810,911
Other income (loss), net	–	345	(24)	–	321
Equity in earnings of subsidiaries	479,236	–	–	(479,236)	–
Interest expense	–	7,769	11,494	–	19,263
Income (loss) before income taxes	479,236	641,846	150,123	(479,236)	791,969
Provision for income taxes	–	253,738	58,995	–	312,733
Net income (loss)	479,236	388,108	91,128	(479,236)	479,236
Comprehensive income (loss)	$ 625,011	$ 534,124	$ 90,297	$ (624,421)	$ 625,011

CONDENSED CONSOLIDATING BALANCE SHEETS

(Unaudited)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
September 30, 2012:					
ASSETS					
Cash and cash equivalents	$ 16,961	$ 1,365	$ 234	$ –	$ 18,560
Restricted cash	127,074	–	–	–	127,074
Accounts receivable	3,269	271,542	22,962	–	297,773
Inventories	–	29,672	958	–	30,630
Other current assets	6,472	355,779	10,459	–	372,710
Total current assets	153,776	658,358	34,613	–	846,747
Intercompany receivables	2,205,219	34	25,142	(2,230,395)	–
Property and equipment	210,717	11,058,390	1,237,796	–	12,506,903
Less: Accumulated depreciation, depletion and amortization	(73,829)	(6,168,742)	(172,384)	–	(6,414,955)
	136,888	4,889,648	1,065,412	–	6,091,948
Investments in subsidiaries (equity method)	2,521,938	–	–	(2,521,938)	–
Other assets	35,276	80,783	18,197	–	134,256
Total assets	$ 5,053,097	$ 5,628,823	$ 1,143,364	$ (4,752,333)	$ 7,072,951
LIABILITIES AND EQUITY					
Accounts payable	$ 133,968	$ 352,240	$ 33,572	$ –	$ 519,780
Other current liabilities	6,962	232,336	2,087	–	241,385
Total current liabilities	140,930	584,576	35,659	–	761,165
Intercompany payables	–	2,003,287	227,108	(2,230,395)	–
Long-term debt	1,695,342	–	–	–	1,695,342
Deferred income taxes	(96,550)	984,116	316,137	–	1,203,703
Other liabilities	60,096	93,475	5,891	–	159,462
Total liabilities	1,799,818	3,665,454	584,795	(2,230,395)	3,819,672
Commitments and contingencies					
Total equity	3,253,279	1,963,369	558,569	(2,521,938)	3,253,279
Total liabilities and equity	$ 5,053,097	$ 5,628,823	$ 1,143,364	$ (4,752,333)	$ 7,072,951

CONDENSED CONSOLIDATING BALANCE SHEETS

(Unaudited)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
December 31, 2011:					
ASSETS					
Cash and cash equivalents	$ 14,711	$ –	$ 916	$ –	$ 15,627
Accounts receivable	2,914	309,038	29,963	–	341,915
Inventories	–	45,260	974	–	46,234
Other current assets	6,087	563,635	4,780	–	574,502
Total current assets	23,712	917,933	36,633	–	978,278
Intercompany receivables	2,053,132	53	23,517	(2,076,702)	–
Property and equipment	180,300	9,731,944	1,148,575	–	11,060,819
Less: Accumulated depreciation, depletion and amortization	(57,254)	(4,220,205)	(137,880)	–	(4,415,339)
	123,046	5,511,739	1,010,695	–	6,645,480
Investments in subsidiaries (equity method)	3,256,195	–	–	(3,256,195)	–
Other assets	28,641	227,152	23,346	–	279,139
Total assets	$ 5,484,726	$ 6,656,877	$ 1,094,191	$ (5,332,897)	$ 7,902,897
LIABILITIES AND EQUITY					
Accounts payable	$ 205,341	$ 332,710	$ 37,276	$ –	$ 575,327
Other current liabilities	5,912	301,170	2,504	–	309,586
Total current liabilities	211,253	633,880	39,780	–	884,913
Intercompany payables	–	1,628,750	447,952	(2,076,702)	–
Long-term debt	1,342,100	–	–	–	1,342,100
Deferred income taxes	(97,045)	1,442,576	241,267	–	1,586,798
Other liabilities	59,114	54,826	5,842	–	119,782
Total liabilities	1,515,422	3,760,032	734,841	(2,076,702)	3,933,593
Commitments and contingencies					
Total equity	3,969,304	2,896,845	359,350	(3,256,195)	3,969,304
Total liabilities and equity	$ 5,484,726	$ 6,656,877	$ 1,094,191	$ (5,332,897)	$ 7,902,897

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

(Unaudited)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
Nine months ended September 30, 2012:					
Net cash provided by (used in) operating activities	$ (55,324)	$ 915,885	$ 331,916	$ –	$ 1,192,477
Investing activities:					
Capital investments	(38,946)	(1,452,061)	(132,744)	–	(1,623,751)
Proceeds from sale of property and equipment	144	169,149	31,868	–	201,161
Transfers to restricted cash	(167,774)	–	–	–	(167,774)
Transfers from restricted cash	40,700	–	–	–	40,700
Other	16,575	(24,340)	13,004	–	5,239
Net cash used in investing activities	(149,301)	(1,307,252)	(87,872)	–	(1,544,425)
Financing activities:					
Intercompany activities	(148,027)	392,732	(244,705)	–	–
Payments on current portion of long-term debt	(600)	–	–	–	(600)
Payments on revolving long-term debt	(1,774,000)	–	–	–	(1,774,000)
Borrowing under revolving long-term debt	1,129,000	–	–	–	1,129,000
Proceeds from issuance of long-term debt	998,780	–	–	–	998,780
Other Items	1,722	–	(11)	–	1,711
Net cash provided by (used in) financing activities	206,875	392,732	(244,716)	–	354,891
Effect of exchange rate changes on cash	–	–	(10)	–	(10)
Increase (decrease) in cash and cash equivalents	2,250	1,365	(682)	–	2,933
Cash and cash equivalents at beginning of year	14,711	–	916	–	15,627
Cash and cash equivalents at end of period	$ 16,961	$ 1,365	$ 234	$ –	$ 18,560

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
Nine months ended September 30, 2011:					
Net cash provided by (used in) operating activities	$ (23,901)	$ 1,146,062	$ 178,050	$ –	$ 1,300,211
Investing activities:					
Capital investments	(53,085)	(1,333,977)	(156,487)	–	(1,543,549)
Proceeds from sale of property and equipment	–	121,281	265	–	121,546
Transfers to restricted cash	(85,040)	–	–	–	(85,040)
Transfers from restricted cash	15,779	–	–	–	15,779
Other	11,046	(31,564)	25,458	–	4,940
Net cash used in investing activities	(111,300)	(1,244,260)	(130,764)	–	(1,486,324)
Financing activities:				–	
Intercompany activities	(44,592)	92,018	(47,426)	–	–
Payments on current portion of long-term debt	(600)	–	–	–	(600)
Payments on revolving long-term debt	(2,575,000)	–	–	–	(2,575,000)
Borrowings under revolving long-term debt	2,753,600	–	–	–	2,753,600
Other items	5,254	–	–	–	5,254
Net cash provided by (used in) financing activities	138,662	92,018	(47,426)	–	183,254
Effect of exchange rate changes on cash	–	–	97	–	97
Increase (decrease) in cash and cash equivalents	3,461	(6,180)	(43)	–	(2,762)
Cash and cash equivalents at beginning of year	8,381	7,631	43	–	16,055
Cash and cash equivalents at end of period	$ 11,842	$ 1,451	$ –	$ –	$ 13,293

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 2011 Annual Report on Form 10-K and analyzes the changes in the results of operations between the three- and nine-month periods ended September 30, 2012 and 2011. 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 2011 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 2011 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 and oil, with our current operations being principally focused within the United States on development of an unconventional gas reservoir located on the Arkansas side of the Arkoma Basin, which we refer to as the Fayetteville Shale play. We are also actively engaged in exploration and production activities in Pennsylvania, where we are targeting the unconventional gas reservoir known as the Marcellus Shale, and to a lesser extent, production activities in Texas and in Arkansas and Oklahoma in the Arkoma Basin. The Company also actively seeks to find and develop new oil and natural gas plays with significant exploration and exploitation potential. 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 primarily through the drillbit. We derive the majority of our operating income and cash flow from the natural gas production of our E&P business and expect this to continue in the future. We expect that growth in our operating income and revenues will primarily depend on natural gas prices and our ability to increase our natural gas production. We expect our natural gas production volumes will continue to increase due to the ongoing development of 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 MMBtu in 2008 to a low of $1.91 per MMBtu in April 2012. Natural gas prices fluctuate due to a variety of factors we cannot control or predict. These factors, which include increased supplies of natural gas due to greater exploration and development activities, weather conditions, political and economic events and competition from other energy sources, impact supply and demand for natural gas, which in turn determines the sale prices for our production. In addition to the factors identified above, the prices we realize for our production are affected by our hedging activities as well as locational differences in market prices.

Three Months Ended September 30, 2012 Compared with Three Months Ended September 30, 2011

We reported a net loss of $144.8 million for the three months ended September 30, 2012, or $0.42 per diluted share, compared to net income of $175.2 million, or $0.50 per diluted share, for the comparable period in 2011. The loss for the three months ended September 30, 2012 includes a $441.5 million, or $276.6 million net of taxes, non-cash ceiling impairment of our natural gas and oil properties.

Our natural gas and oil production increased to 144.3 Bcfe for the three months ended September 30, 2012, up 12% from the three months ended September 30, 2011. The 15.4 Bcfe increase in our third quarter 2012 production was primarily due to a 11.7 Bcf increase in net production from our Fayetteville Shale play and a 7.7 Bcf increase in net production from our Marcellus Shale properties, which more than offset a combined 4.0 Bcfe decrease in net production from our East Texas and Arkoma Basin properties primarily due to the sale of certain East Texas oil and natural gas properties. The average price realized for our gas production, including the effects of hedges, decreased 21% to $3.40 per Mcf for the three months ended September 30, 2012 compared to $4.30 per Mcf for the same period in 2011.

Our E&P segment reported an operating loss of $296.1 million for the three months ended September 30, 2012, down $524.6 million from the comparable period of 2011, due to the $441.5 million non-cash ceiling test impairment of our natural gas and oil properties, decreased prices realized from the sale of our natural gas production of $129.9 million and an increase in operating costs and expenses of $19.7 million associated with higher natural gas production volumes, which were partially offset by an increase in revenues of $66.7 million from higher natural gas production volumes.

Operating income for our Midstream Services segment was $75.5 million for the three months ended September 30, 2012, up from $66.8 million for the three months ended September 30, 2011, due to an increase of $15.8 million in gas gathering revenues, which was partially offset by a decrease of $2.0 million in the margin generated from our gas marketing activities and a $5.1 million increase in operating costs and expenses associated with an increase in gas volumes gathered of 23.8 Bcf, exclusive of gas purchase costs.

Capital investments were $424.9 million for the three months ended September 30, 2012, of which $385.6 million was invested in our E&P segment, compared to $470.4 million for the same period of 2011, of which $421.2 million was invested in our E&P segment.

Nine Months Ended September 30, 2012 Compared with Nine Months Ended September 30, 2011

We reported a net loss of $525.2 million for the nine months ended September 30, 2012, or $1.51 per diluted share, compared to net income of $479.2 million, or $1.37 per diluted share, for the comparable period in 2011.

Our natural gas and oil production increased to 415.1 Bcfe for the nine months ended September 30, 2012, up 13% from 366.7 Bcfe for the nine months ended September 30, 2011. The 48.4 Bcfe increase in 2012 production was primarily due to a 40.0 Bcf increase in net production from our Fayetteville Shale play and an 19.1 Bcf increase in net production from our Marcellus Shale properties, which more than offset a combined 10.7 Bcfe decrease in net production from our East Texas and Arkoma Basin properties, primarily due to the sale of certain East Texas oil and natural gas properties. The average price realized for our gas production, including the effects of hedges, decreased approximately 21% to $3.34 per Mcf for the nine months ended September 30, 2012 compared to $4.24 per Mcf for the same period in 2011.

Our E&P segment reported an operating loss of $1,039.7 million for the nine months ended September 30, 2012, down $1,669.0 million from the comparable period of 2011, due to the $1,377.4 million non-cash ceiling test impairment of our natural gas and oil properties, decreased prices realized from the sale of our natural gas production of $376.1 million and an increase in operating costs and expenses of $118.5 million associated with higher natural gas production volumes, which were partially offset by an increase in revenues of $205.9 million from higher natural gas production volumes.

Operating income for our Midstream Services segment was $216.6 million for the nine months ended September 30, 2012, up from $180.4 million for the nine months ended September 30, 2011, due to an increase of $51.0 million in gathering revenues, which was partially offset by a $12.9 million increase in operating costs and expenses, exclusive of gas purchase costs, associated with the increase in gas volumes gathered of 77.2 Bcf and a decrease of $1.9 million in the margin generated from our gas marketing activities.

Net cash provided by operating activities decreased 8% to $1,192.5 million for the nine months ended September 30, 2012, from $1,300.2 million for the same period in 2011, due to a decrease in net income adjusted for non-cash expenses primarily as a result of a decrease in revenues arising from lower realized gas prices, partially offset by higher natural gas production and gathering volumes and an increase in changes in working capital. Capital investments were $1,586.6 million for the nine months ended September 30, 2012, of which $1,450.6 million was invested in our E&P segment, compared to $1,556.9 million for the same period of 2011, of which $1,365.4 million was invested in our E&P segment.

Recent Developments

Sale of East Texas Assets

In May 2012, we sold certain oil and natural gas leases, wells and gathering equipment in East Texas for approximately $168.0 million, excluding typical purchase price adjustments. The proceeds were deposited with a qualified intermediary to facilitate potential like-kind exchange transactions pursuant to Section 1031 of the Internal Revenue Code and, unless utilized for one or more like-kind exchange transactions, were restricted in their use until October 2012. The assets included in the sale represented all of our interests and related assets in the Overton Field in Smith County. Our net production from the sold assets was approximately 24.0 MMcfe per day as of the closing date and our net proved reserves were approximately 143.0 Bcfe at December 31, 2011.

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 September 30,		For the nine months ended September 30,	
	2012	2011	2012	2011
Revenues (in thousands)	$ 492,223	$ 555,620	$ 1,388,440	$ 1,561,658
Impairment of natural gas and oil properties (in thousands)	$ 441,465	$ –	$ 1,377,364	$ –
Operating costs and expenses (in thousands)	$ 346,866	$ 327,144	$ 1,050,813	$ 932,360
Operating income (loss) (in thousands)	$ (296,108)	$ 228,476	$ (1,039,737)	$ 629,298
Gas production (Bcf)	144.2	128.7	414.7	366.2
Oil production (MBbls)	19	24	59	79
Total production (Bcfe)	144.3	128.9	415.1	366.7
Average gas price per Mcf, including hedges	$ 3.40	$ 4.30	$ 3.34	$ 4.24
Average gas price per Mcf, excluding hedges	$ 2.35	$ 3.71	$ 2.12	$ 3.75
Average oil price per Bbl	$ 99.67	$ 88.35	$ 102.89	$ 93.54
Average unit costs per Mcfe:				
Lease operating expenses	$ 0.79	$ 0.86	$ 0.80	$ 0.84
General & administrative expenses	$ 0.21	$ 0.25	$ 0.26	$ 0.26
Taxes, other than income taxes	$ 0.09	$ 0.11	$ 0.10	$ 0.11
Full cost pool amortization	$ 1.28	$ 1.28	$ 1.33	$ 1.29

Revenues

Revenues for our E&P segment were down $63.4 million, or 11%, for the three months ended September 30, 2012 compared to the same period in 2011. Higher natural gas production volumes in the third quarter of 2012 increased revenues by $66.7 million and lower realized prices for our gas production decreased revenue by $129.9 million compared to the third quarter of 2011. E&P revenues were down $173.2 million, or 11% for the nine months ended September 30, 2012. Higher natural gas production volumes in the first nine months of 2012 increased revenues by $205.9 million while lower realized prices for our gas production decreased revenue by $376.1 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 prices are difficult to predict and subject to wide price fluctuations. As of October 26, 2012, we had hedged 67.2 Bcf of our remaining 2012 gas production and 185.6 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 September 30, 2012, our natural gas and oil production increased 12% to 144.3 Bcfe, up from 128.9 Bcfe from the same period in 2011, and was produced entirely by our properties in the United States. The 15.4 Bcfe increase in our 2012 production was primarily due to a 11.7 Bcf increase in net production from our Fayetteville Shale play and a 7.7 Bcf increase in net production from our Marcellus Shale properties, which more than offset a combined 4.0 Bcfe decrease in net production from our East Texas and Arkoma Basin properties. Net production from our Fayetteville Shale and Marcellus Shale properties was 123.6 Bcf and 15.1 Bcf, respectively, for the three months ended September 30, 2012 compared to 111.9 Bcf and 7.4 Bcf, respectively, for the same period in 2011. For the nine months ended September 30, 2012, our natural gas and oil production increased 13% to 415.1 Bcfe, up from 366.7 Bcfe from the same period in 2011, and was produced entirely by our properties in the United States. The 48.4 Bcfe increase in our 2012 production was primarily due to a 40.0 Bcf increase in net production from our Fayetteville Shale play and an 19.1 Bcf increase in net production from our Marcellus Shale properties, which more than offset a combined 10.7 Bcfe decrease in net production from our East Texas and Arkoma Basin properties. Net production from our Fayetteville Shale and Marcellus Shale properties was 360.4 Bcf and 34.3 Bcf, respectively, for the nine months ended September 30, 2012 compared to 320.4 Bcf and 15.2 Bcf, respectively, for the same period in 2011.

Commodity Prices

The average price realized for our natural gas production, including the effects of hedges, decreased to $3.40 per Mcf for the three months ended September 30, 2012, as compared to $4.30 for the same period in 2011. The decrease was the result of a $1.36 per Mcf decrease in average natural gas prices, excluding hedges, which was partially offset by our price hedging activities. Our hedging activities increased the average natural gas price $1.05 per Mcf for the three months ended September 30, 2012 compared to an increase of $0.59 per Mcf for the same period in 2011. The average price realized for our natural gas production, including the effects of hedges, decreased 21% to $3.34 per Mcf for the nine months ended September 30, 2012, as compared to the same period in 2011. The decrease in the average price realized for nine months ended September 30, 2012, as compared to the same period in 2011, primarily reflects the $1.63 Mcf decrease in average gas prices, excluding hedges, which was partially offset by the $0.73 Mcf increased effect of our price hedging activities. Our hedging activities increased the average natural gas price $1.22 per Mcf for the nine months ended September 30, 2012 compared to an increase of $0.49 per Mcf for the same period in 2011. 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).

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 nine months ended September 30, 2012 of $2.12 per Mcf was approximately $0.47 lower than the average monthly NYMEX settlement price, primarily due to locational basis differentials and transportation costs. We protected approximately 56% of our natural gas production for the nine months ended September 30, 2012 from the impact of widening basis differentials through our hedging activities and sales arrangements. For the remainder of 2012, we expect our total natural gas sales discount to NYMEX to be approximately $0.50 per Mcf. At September 30, 2012, we had basis protected on approximately 73 Bcf of our remaining 2012 expected natural gas production through financial hedging activities and physical sales arrangements at a differential to NYMEX natural gas prices of approximately ($0.03) per Mcf, excluding transportation and fuel charges. Additionally, at September 30, 2012, we had basis protected on approximately 191 Bcf and 25 Bcf of our 2013 and 2014 expected natural gas production, respectively, through financial hedging activities and physical sales arrangements.

In addition to the basis hedges discussed above, at September 30, 2012, we had NYMEX fixed price hedges in place on notional volumes of 46.7 Bcf of our remaining 2012 natural gas production at an average price of $5.01 per MMBtu and collars in place on notional volumes of 20.2 Bcf of our remaining 2012 gas production at an average floor and ceiling price of $5.50 and $6.67 per MMBtu, respectively.

As of September 30, 2012, we had NYMEX fixed price hedges in place on notional volumes of 185.6 Bcf of our 2013 natural gas production at an average price of $5.06 per MMBtu.

Operating Income

We recorded an operating loss from our E&P segment of $296.1 million for the three months ended September 30, 2012, which represents a decline of $524.6 million from the same period in 2011. The operating loss was primarily due to the $441.5 million non-cash ceiling test impairment, driven by lower natural gas prices, a decline in revenues of $63.4 million, and an increase in other operating costs and expenses of $19.7 million associated with higher natural gas production volumes. We recorded an operating loss from our E&P segment of $1,039.7 million for the nine months ended September 30, 2012, which represents a decline of $1,669.0 million from the same period in 2011. The operating loss was primarily due to the $1,377.4 million non-cash ceiling test impairment, driven by lower natural gas prices, a decline in revenues of $173.2 million, and an increase in other operating costs and expenses of $118.5 million associated with higher natural gas production volumes.

Operating Costs and Expenses

Lease operating expenses per Mcfe for our E&P segment were $0.79 for three months ended September 30, 2012 compared to $0.86 for the same period in 2011. The decrease in lease operating expenses per unit of production for the three months ended September 30, 2012 as compared to the same period of 2011, was primarily due to lower compression, and salt water disposal costs in our Fayetteville Shale play. Lease operating expenses per Mcfe for our E&P segment were $0.80 for the nine months ended September 30, 2012 compared to $0.84 for the same period in 2011. The decrease in lease operating expense per unit of production for the nine months ended September 30, 2012 as compared to the same period of 2011, was primarily due to lower compression costs related to our Fayetteville Shale play.

General and administrative expenses per Mcfe for our E&P segment decreased to $0.21 for the three months ended September 30, 2012 from $0.25 for the same period in 2011 due to decreased personnel costs and professional fees. General and administrative expenses per Mcfe remained flat at $0.26 for the nine months ended September 30, 2012 compared to the same period in 2011. In total, general and administrative expenses for our E&P segment were $30.3 million for the three months ended September 30, 2012 compared to $32.6 million for the same period in 2011, and were $107.6 million for the nine months ended September 30, 2012 compared to $96.7 million for the same period in 2011. The increase in general and administrative expenses for the nine months ended September 30, 2012 as compared to the same period of 2011, was primarily a result of increased personnel and information system costs associated with the expansion of our E&P operations.

Taxes other than income taxes per Mcfe decreased to $0.09 for the three months ended September 30, 2012 compared to $0.11 for the same period in 2011 and decreased to $0.10 for the nine months ended September 30, 2012 compared to $0.11 for the same period in 2011. 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 September 30, 2012 and 2011, respectively. For the first nine months of 2012, our full cost pool amortization rate averaged $1.33 per Mcfe compared to $1.29 per Mcfe for the same period in 2011. 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. Using the first-day-of-the-month prices of natural gas for the first ten months of 2012 and NYMEX strip prices for the remainder of 2012, as applicable, the prices required to be used to determine the ceiling amount in our full cost ceiling test is likely to require a write-down in the fourth quarter of 2012.

Unevaluated costs excluded from amortization were $1,130.4 million at September 30, 2012 compared to $942.9 million at December 31, 2011. The increase in unevaluated costs since December 31, 2011 primarily resulted from an increase in our wells in progress. Unevaluated costs excluded from amortization at September 30, 2012 included $36.0 million related to our properties in Canada, compared to $27.9 million at December 31, 2011.

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 September 30,		For the nine months ended September 30,	
	2012	2011	2012	2011
	($ in thousands, except volumes)			
Revenues – marketing	$ 481,845	$ 639,175	$ 1,289,818	$ 1,887,383
Revenues – gathering	$ 120,494	$ 104,656	$ 347,370	$ 296,325
Gas purchases – marketing	$ 474,628	$ 629,899	$ 1,267,117	$ 1,862,736
Operating costs and expenses	$ 52,223	$ 47,095	$ 153,473	$ 140,574
Operating income	$ 75,488	$ 66,837	$ 216,598	$ 180,398
Gas volumes marketed (Bcf)	171.2	153.3	498.7	450.4
Gas volumes gathered (Bcf)	214.7	190.9	622.9	545.7

Revenues

Revenues from our marketing activities were down 25% to $481.8 million for the three months ended September 30, 2012 and were down 32% to $1,289.8 million for the nine months ended September 30, 2012 compared to the respective periods of 2011. For the three months ended September 30, 2012, the volumes marketed increased 12% and the price received for volumes marketed decreased 32% compared to the same period in 2011. For the nine months ended September 30, 2012, the volumes marketed increased 11% and the price received for volumes marketed decreased 38% compared to the same period in 2011. Increases and decreases in marketing revenues due to changes in commodity prices are largely offset by corresponding changes in gas purchase expenses. Of the total volumes marketed, production from our affiliated E&P operated wells accounted for 96% of the marketed volumes for the three months ended September 30, 2012 and 2011, respectively. For the nine months ended September 30, 2012 and 2011, production from our affiliated E&P operated wells accounted for 95% and 94% of the marketed volumes, respectively.

Revenues from our gathering activities were up 15% to $120.5 million for the three months ended September 30, 2012 and up 17% to $347.4 million for the nine months ended September 30, 2012 compared to the respective periods in 2011. The increases in gathering revenues resulted primarily from a 12% increase in gas volumes gathered for the three months ended September 30, 2012 and a 14% increase in gas volumes gathered for the nine months ended September 30, 2012 compared to the respective periods in 2011. A majority of the increase in gathering revenues for the three months and nine months ended September 30, 2012 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 plays are developed and production increases.

Operating Income

Operating income from our Midstream Services segment increased to $75.5 million for the three months ended September 30, 2012 compared to $66.8 million for the same period in 2011 and increased to $216.6 million for the nine months ended September 30, 2012 compared to $180.4 million for the same period in 2011. The increases in operating income reflect the increases in gas volumes gathered which primarily resulted from our increased E&P production volumes. The $8.7 million increase in operating income for the three months ended September 30, 2012 was primarily due to an increase of $15.8 million in gathering revenues, which was partially offset by a decrease of $2.0 million in the margin generated from our gas marketing activities and a $5.1 million increase in operating costs and expenses, exclusive of gas purchase costs, associated with the increase in gas volumes gathered. The $36.2 million increase in operating income for the nine months ended September 30, 2012 was primarily due to an increase of $51.0 million in gathering revenues, which was offset by a decrease of $1.9 million in the margin generated from our gas marketing activities and a $12.9 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 $7.2 million for the three months ended September 30, 2012 compared to $9.3 million for the three months ended September 30, 2011. The margin generated from gas marketing activities was $22.7 million for the nine months ended September 30, 2012 compared to $24.6 million for the nine months ended September 30, 2011. Margins are primarily driven by volumes of natural 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 natural gas marketing activities to provide margin protection. We refer you to Item 3, "Quantitative and Qualitative Disclosures about Market Risks" included in this Form 10-Q for additional information.

Interest Expense

Interest expense, net of capitalization, increased to $10.6 million for the three months ended September 30, 2012, compared to $5.7 million for the same period in 2011, and increased to $26.3 million for the nine months ended September 30, 2012 compared to $19.3 million for the same period in 2011. The increase in interest expense, net of capitalization, for the three- and nine-month periods ended September 30, 2012 was primarily due to our increased borrowing level, partially offset by an increase in capitalized interest. We capitalized interest of $15.9 million and $45.9 million for the three- and nine-month periods ended September 30, 2012, respectively, compared to $11.9 million and $32.5 million for the same periods in 2011. 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 37.9% and 39.5% for the nine months ended September 30, 2012 and 2011, respectively. The effective tax rate is lower in 2012 primarily due to the $1,377.4 million non-cash impairment of our gas and oil properties and state income taxes. For the nine months ended September 30, 2012, we recorded an income tax benefit of $320.4 million compared to an income tax expense of $312.7 million for the same period in 2011, primarily as a result of the non-cash impairment.

Stock-Based Compensation Expense

We recognized expense of $2.7 million and capitalized $2.5 million for stock-based compensation during the three-month period ended September 30, 2012 compared to $1.9 million expense and $2.2 million capitalized for the comparable period in 2011. We recognized expense of $8.2 million and capitalized $7.8 million for stock-based compensation costs recognized during the nine-month period ended September 30, 2012 compared to $6.6 million expense and $6.0 million capitalized for the comparable period in 2011. 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 Standard

In December 2011, the FASB issued guidance on offsetting assets and liabilities and disclosure requirements in Accounting Standards Update No. 2011-11, *Disclosures about Offsetting Assets and Liabilities* ("Update 2011-11"). Update 2011-11 requires that entities disclose both gross and net information about instruments and transactions eligible for offset in the statement of financial position as well as instruments and transactions subject to an agreement similar to a master netting agreement. In addition, the standard requires disclosure of collateral received and posted in connection with master netting agreements or similar arrangements. Update 2011-11 is effective for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. The implementation of the disclosure requirement is not expected to have a material impact on the Company's consolidated 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 2012, assuming natural gas prices remain at current levels, we may draw on a portion of the funds available under our Credit Facility to fund our planned capital investments (discussed below under “Capital Investments”). We refer you to Note 9 to the unaudited condensed consolidated financial statements included in this Form 10-Q and the section below under “Financing Requirements” for additional discussion of our Credit Facility.

Net cash provided by operating activities decreased 8% to $1,192.5 million for the nine months ended September 30, 2012 compared to $1,300.2 million for the same period in 2011, due to a decrease in net income adjusted for non-cash expenses primarily resulting from decreased revenues due to lower realized gas prices, partially offset by higher natural gas production and gathering volumes and an increase in changes in working capital. During the nine months ended September 30, 2012, requirements for our capital investments were funded primarily from our cash generated by operating activities, cash and cash equivalents, remaining net proceeds from the debt offering, sale of certain East Texas oil and natural gas properties, and borrowings under our Credit Facility. For the nine months ended September 30, 2012, cash generated from our operating activities funded 73% of our cash requirements for capital investments and 84% for the nine months ended September 30, 2011.

We believe that our operating cash flow, cash equivalents, and available funds under our Credit Facility will be adequate to meet our capital and operating requirements for 2012. 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 $1.6 billion for the nine months ended September 30, 2012 and 2011, respectively. Our E&P segment investments were $1.5 billion for the nine months ended September 30, 2012 compared to $1.4 billion for the comparable period in 2011. Our E&P segment capitalized internal costs of $113.1 million for the nine months ended September 30, 2012 compared to $109.6 million for the comparable period in 2011. 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.

Our capital investments for 2012 are planned to be $2.1 billion, consisting of $1.8 billion for E&P, $193 million for Midstream Services and $91 million for corporate and other purposes. Of the approximate $1.8 billion, we expect to allocate approximately $1.1 billion to our Fayetteville Shale play and approximately $500 million to our Marcellus Shale play. Our planned level of capital investments in 2012 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 remaining 2012 capital investment program is expected to be funded through cash flow from operations, cash and cash equivalents, May 2012 sale of certain East Texas oil and natural gas properties, and borrowings under our Credit Facility. The remaining planned capital program for 2012 is flexible and can be modified, including downward, if the low natural gas price environment persists for an extended period of time.

Financing Requirements

Our total debt outstanding was $1.7 billion at September 30, 2012 compared to $1.3 billion at December 31, 2011.

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 $26.5 million outstanding under our revolving credit facility at September 30, 2012 compared to $671.5 million at December 31, 2011.

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 long term debt rating of Baa3 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 September 30, 2012, our capital structure as determined under our Credit Facility was 30% debt and 70% equity, which excluded hedging activities, pension and other postretirement liabilities, and the effect of the full cost ceiling impairment. We were in compliance with all of the covenants of our Credit Facility at September 30, 2012. 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.

In March 2012, we issued $1 billion of 4.10% Senior Notes due 2022 in a private placement. A portion of the net proceeds of the offering were used to repay the amounts outstanding under the Company's revolving credit facility and the remaining proceeds were used for general corporate purposes.

At September 30, 2012, our capital structure consisted of 34% debt and 66% equity (exclusive of cash and cash equivalents and restricted cash) and $145.6 million in cash and cash equivalents and restricted cash, compared to 25% debt and 75% equity at December 31, 2011. Equity at September 30, 2012 included an accumulated other comprehensive gain of $206.7 million related to our hedging activities, partially offset by $15.1 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 September 30, 2012 and does not necessarily reflect the value that we will receive or pay when the hedges are ultimately settled, nor does it take into account revenues to be received associated with the physical delivery of sales volumes hedged.

Our hedges allow us to ensure a certain level of cash flow to fund our operations. At October 26, 2012, we had NYMEX commodity price hedges in place on 67.2 Bcf of our remaining targeted 2012 natural gas production and 185.6 Bcf of our expected 2013 natural gas production. The amount of long-term debt we incur will be largely dependent upon commodity prices and our capital investment plans.

Contractual Obligations and Contingent Liabilities and Commitments

We have various contractual obligations in the normal course of our operations and financing activities. There have been no material changes to our contractual obligations from those disclosed in our 2011 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. The Company commenced its Canada exploration program in 2010 and, as of September 30, 2012, no liability has been recognized in connection with the promissory notes due to the Company's investments in New Brunswick as of September 30, 2012 and its future investment plans.

Substantially all of our employees are covered by defined pension and postretirement benefit plans. As of September 30, 2012, we have contributed $11.0 million to the pension plans and $0.1 million to the postretirement benefit plan, with no further contributions planned in 2012. At September 30, 2012, we recognized a liability of $18.3 million as a result of the underfunded status of our pension and other postretirement benefit plans compared to a liability of $20.5 million at December 31, 2011.

We are subject to litigation, claims and proceedings (including with respect to environmental matters) that arise in the ordinary course of business. Management believes, individually or in aggregate, such litigation, claims and proceedings will not have a material adverse impact on our financial position, results of operations, or cash flows, but these matters are subject to inherent uncertainties and management's view may change in the future. If an unfavorable final outcome were to occur, there exists the possibility of a material impact on our financial position, results of operations or cash flows for the period in which the effect becomes reasonably estimable. We accrue for such items when a liability is both probable and the amount can be reasonably estimated. 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 positive working capital of $85.6 million at September 30, 2012 and positive working capital of $93.4 million at December 31, 2011. Current assets decreased by $131.5 million during the nine months ended September 30, 2012 primarily due to a $213.6 million decrease in current hedging asset and a $44.1 million decrease in accounts receivable. These decreases were partially offset by a $130.0 million increase in cash and cash equivalents and restricted cash, which is primarily the result of our sale of certain East Texas assets, and to a lesser extent from increased borrowing. Current liabilities decreased by $123.7 million during the nine months ended September 30, 2012 primarily as a result of a $77.7 million decrease in current deferred income taxes and a $45.4 million decrease in accounts payable. 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 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. No single customer accounted for greater than 10% of revenues for the nine months ended September 30, 2012. See "Commodities Risk" below for discussion of credit risk associated with commodities trading.

Interest Rate Risk

At September 30, 2012, we had $1.7 billion of total debt with a weighted average interest rate of 5.4%. Our revolving credit facility has a floating interest rate (2.20% at September 30, 2012). At September 30, 2012, we had borrowings outstanding of $26.5 million 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 September 30, 2012, the fair value of our financial instruments related to natural gas production was a $347.8 million asset.

	Volume (Bcf)	Weighted Average Price to be Swapped ($/MMBtu)	Weighted Average Floor Price ($/MMBtu)	Weighted Average Ceiling Price ($/MMBtu)	Weighted Average Basis Differential ($/MMBtu)	Fair value at September 30, 2012 ($ in millions)
Natural Gas (Bcf):						
Fixed Price Swaps:						
2012	46.7	$ 5.01	$ –	$ –	$ –	$ 78.5
2013	185.6	$ 5.06	$ –	$ –	$ –	$ 222.4
Floating Price Swaps:						
2012	0.7	$ 5.66	$ –	$ –	$ –	$ –
Costless-Collars:						
2012	20.2	$ –	$ 5.50	$ 6.67	$ –	$ 44.0
Basis Swaps:						
2012	9.2	$ –	$ –	$ –	$ 0.12	$ 0.7
2013	30.1	$ –	$ –	$ –	$ 0.07	$ 1.7
2014	9.1	$ –	$ –	$ –	$ (0.03)	$ 0.5

At September 30, 2012, our basis swaps did not qualify for hedge accounting treatment. Changes in the fair value of derivatives that do not qualify as cash flow hedges are recorded in gas and oil sales. For the nine months ended September 30, 2012, we recorded an unrealized loss of $0.3 million related to the basis swaps that did not qualify for hedge accounting treatment and an unrealized gain of $2.0 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.

ITEM 4. CONTROLS AND PROCEDURES.

Evaluation of Disclosure Controls and Procedures

We have performed an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures, as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the Exchange Act). Our disclosure controls and procedures are the controls and other procedures that we have designed to ensure that we record, process, accumulate and communicate information to our management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosures and submission within the time periods specified in the SEC's rules and forms. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those determined to be effective can provide only a level of reasonable assurance with respect to financial statement preparation and presentation. Based on the evaluation, our management, including our Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures were effective as of September 30, 2012.

Changes in Internal Control over Financial Reporting

In January 2012, the Company implemented certain modules in its new Enterprise Resource Planning (ERP) system, including but not limited to, accounting, operational, and supply chain. Implementing an ERP system involves significant changes in business processes that management believes will provide several benefits including more standardized and efficient processes throughout the Company. This implementation has resulted in material changes to the Company's internal controls over financial reporting, as that term is defined Rules 13(a)-15(f) and 15(d)-15(f) under the Exchange Act, for the three months ended September 30, 2012. Therefore, the Company has modified the design, operation and documentation of certain internal control processes and procedures to address the new environment associated with implementation. The system changes were undertaken to integrate systems and consolidate information, and were not undertaken in response to any perceived or actual deficiency in the Company's internal controls 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 273rd 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 $55.0 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 $46.0 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. On August 24, 2011, a judgment was entered pursuant to which plaintiff and intervenor are entitled to recover approximately $11.4 million in actual damages and approximately $23.9 million in disgorgement as well as prejudgment interest and attorneys' fees which currently are estimated to be up to $8.9 million and all costs of court of the plaintiff and intervenor. On September 23, 2011, SEPCO filed a motion for a new trial and on November 18, 2011 filed a notice of appeal. On November 30,2011, the court approved SEPCO's supersedeas bond in the amount of $14.1 million, which stays execution on the judgment pending appeal. The bond covers the $11.4 million judgment for actual damages, plus $1.3 million in pre-judgment interest, $1.3 million in post-judgment interest (estimating two years for the duration of appeal), and court costs. On April 17, 2012, SEPCO filed an unopposed motion for the appellate court's permission to extend the deadline for filing its appeal to May 23, 2012.

On June 22, 2012, SEPCO filed its appellate brief and, on June 25, 2012, plaintiff and intervenor filed a cross-appellate brief seeking limited remand to reassess the disgorgement determination. The parties are seeking a final extension of their deadlines to respond to the opposing party's brief. Thus, we expect that plaintiff and intervenor will file their response to SEPCO's appellate brief on November 7, 2012, and SEPCO will file its response to plaintiff and intervenor's cross-appellate brief on the same day. Oral arguments are expected to occur in spring 2013. 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 judgments to date, that SEPCO's potential liability would be up to $44.2 million, including 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.

On February 20, 2012, the Company became aware that SEPCO was named as a defendant in the matter of Gery Muncey v. Southwestern Energy Production Company, et al filed in the District Court of San Augustine County in Texas on January 31, 2012. The plaintiff in this case is also the intervenor in the Tovah Energy matter described above and alleges various claims including fraud, misappropriation and breach of fiduciary duty that are purported as independent of the claims alleged in the Tovah Energy matter but arise from the substantially same circumstances involved in the Tovah Energy matter. The plaintiff is seeking value for various royalty and override ownership interests in wells drilled, disgorgement of profits and punitive damages. SEPCO's motion for summary judgment was granted on July 9, 2012. On August 22, 2012, the court signed a final take-nothing judgment in SEPCO's favor. Muncey has not filed any post-judgment motions or a notice of appeal, and the deadlines for filing same have now passed. This matter has been resolved in SEPCO's favor and is now over.

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 therefore 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.

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 2011 Annual Report on Form 10-K.

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

Not applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES.

Not applicable.

ITEM 4. MINE SAFETY DISCLOSURES.

Our sand mining operations, in support of our E&P business, are subject to regulation by the Federal Mine Safety and Health Administration under the Federal Mine Safety and Health Act of 1977. Information concerning mine safety violations or other regulatory matters required by section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.106) is included in Exhibit 95.1 to this Form 10-Q.

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.
(95.1)	Mine Safety Disclosure.
(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: November 1, 2012

/s/ R. CRAIG OWEN
R. Craig Owen
Senior Vice President
and Chief Financial Officer