

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

Form 10-Q

(Mark One)

Quarterly Report pursuant to Section 13 or 15(d) of the Securities
Exchange Act of 1934

For the quarterly period ended **March 31, 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

(State or other jurisdiction of incorporation or organization)

71-0205415

(I.R.S. Employer Identification No.)

**2350 North Sam Houston Parkway East, Suite 125,
Houston, Texas**

(Address of principal executive offices)

77032

(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 May 1, 2012
Common Stock, Par Value \$0.01	349,124,547

SOUTHWESTERN ENERGY COMPANY

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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 March 31,	
	2012	2011
	(in thousands, except share/per share amounts)	
Operating Revenues:		
Gas sales	\$ 463,768	\$ 467,929
Gas marketing	148,051	171,098
Oil sales	2,528	2,727
Gas gathering	42,122	34,581
	<u>656,469</u>	<u>676,335</u>
Operating Costs and Expenses:		
Gas purchases – midstream services	146,676	170,230
Operating expenses	60,958	56,798
General and administrative expenses	48,826	37,117
Depreciation, depletion and amortization	193,627	163,447
Taxes, other than income taxes	20,422	16,092
	<u>470,509</u>	<u>443,684</u>
Operating Income	<u>185,960</u>	<u>232,651</u>
Interest Expense:		
Interest on debt	19,735	15,044
Other interest charges	991	1,511
Interest capitalized	(13,388)	(9,119)
	<u>7,338</u>	<u>7,436</u>
Other Income (Loss), Net	<u>(200)</u>	<u>374</u>
Income Before Income Taxes	178,422	225,589
Provision for Income Taxes:		
Current	168	100
Deferred	70,550	88,880
	<u>70,718</u>	<u>88,980</u>
Net Income	<u>\$ 107,704</u>	<u>\$ 136,609</u>
Earnings Per Share:		
Net income attributable to Southwestern Energy stockholders - Basic	<u>\$ 0.31</u>	<u>\$ 0.39</u>
Net income attributable to Southwestern Energy stockholders - Diluted	<u>\$ 0.31</u>	<u>\$ 0.39</u>
Weighted Average Common Shares Outstanding:		
Basic	<u>348,000,074</u>	<u>346,833,906</u>
Diluted	<u>349,990,725</u>	<u>349,697,327</u>

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

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

	For the three months ended	
	March 31,	
	2012	2011
	(in thousands)	
Net income	\$ 107,704	\$ 136,609
Change in derivatives:		
Reclassification to earnings ⁽¹⁾	(97,942)	(31,658)
Ineffectiveness ⁽²⁾	(3,157)	(58)
Change in fair value of derivative instruments ⁽³⁾	166,934	6,724
Total change in derivatives	65,835	(24,992)
Change in value of pension and other postretirement liabilities:		
Amortization of prior service cost included in net periodic pension cost ⁽⁴⁾	254	197
Change in currency translation adjustment	481	262
Comprehensive income	\$ 174,274	\$ 112,076

(1) Net of (\$63.7) and (\$20.2) million in taxes for the three months ended March 31, 2012 and 2011, respectively.

(2) Net of (\$2.1) and (\$0.1) million in taxes for the three months ended March 31, 2012 and 2011, respectively.

(3) Net of \$108.5 and \$4.3 million in taxes for the three months ended March 31, 2012 and 2011, respectively.

(4) Net of \$0.2 and \$0.1 million in taxes for the three months ended March 31, 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)

	March 31, 2012	December 31, 2011
ASSETS	(in thousands)	
Current Assets:		
Cash and cash equivalents	\$ 206,167	\$ 15,627
Accounts receivable	299,316	341,915
Inventories	37,323	46,234
Hedging asset	620,711	514,465
Other	64,890	60,037
Total current assets	1,228,407	978,278
Property and Equipment:		
Natural gas and oil properties, using the full cost method, including \$1,128.5 million in 2012 and \$942.9 million in 2011 excluded from amortization	10,080,579	9,544,708
Gathering systems	1,006,487	980,647
Other	556,888	535,464
Total property and equipment	11,643,954	11,060,819
Less: Accumulated depreciation, depletion and amortization	4,617,882	4,415,339
	7,026,072	6,645,480
Other Assets	299,682	279,139
TOTAL ASSETS	\$ 8,554,161	\$ 7,902,897
LIABILITIES AND EQUITY		
Current Liabilities:		
Current portion of long-term debt	\$ 1,200	\$ 1,200
Accounts payable	512,017	514,071
Taxes payable	48,976	40,691
Interest payable	13,847	20,565
Advances from partners	118,317	84,082
Hedging liability	14,578	12,458
Current deferred income taxes	234,249	194,163
Other	17,460	17,683
Total current liabilities	960,644	884,913
Long-Term Debt	1,669,380	1,342,100
Other Liabilities:		
Deferred income taxes	1,660,284	1,586,798
Long-term hedging liability	136	55
Pension and other postretirement liabilities	20,284	20,338
Other long-term liabilities	91,674	99,389
	1,772,378	1,706,580
Commitments and Contingencies		
Equity:		
Common stock, \$0.01 par value; authorized 1,250,000,000 shares; issued 349,227,496 shares in 2012 and 349,058,501 in 2011	3,492	3,491
Additional paid-in capital	911,646	903,399
Retained earnings	2,763,918	2,656,214
Accumulated other comprehensive income	474,998	408,428
Common stock in treasury, 100,970 shares in 2012 and 98,889 in 2011	(2,295)	(2,228)
Total equity	4,151,759	3,969,304
TOTAL LIABILITIES AND EQUITY	\$ 8,554,161	\$ 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 three months ended	
	March 31,	
	2012	2011
	(in thousands)	
Cash Flows From Operating Activities		
Net income	\$ 107,704	\$ 136,609
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	194,439	164,667
Deferred income taxes	70,550	88,880
Unrealized gain on derivatives	(7,324)	(1,080)
Stock-based compensation	2,844	2,450
Other	2,607	6
Change in assets and liabilities:		
Accounts receivable	42,604	11,983
Inventories	3,335	8,625
Accounts payable	4,912	(10,347)
Taxes payable	8,285	(13,645)
Interest payable	(6,717)	(9,813)
Advances from partners	34,235	11,600
Other assets and liabilities	(12,811)	6,544
Net cash provided by operating activities	<u>444,663</u>	<u>396,479</u>
Cash Flows From Investing Activities		
Capital investments	(557,631)	(526,139)
Proceeds from sale of property and equipment	651	11,056
Other	1,770	(375)
Net cash used in investing activities	<u>(555,210)</u>	<u>(515,458)</u>
Cash Flows From Financing Activities		
Payments on revolving long-term debt	(1,271,300)	(782,800)
Borrowings under revolving long-term debt	599,800	892,700
Proceeds from issuance of long-term debt	998,780	—
Debt issuance costs	(8,183)	—
Change in bank drafts outstanding	(20,520)	17,749
Revolving credit facility costs	—	(10,103)
Proceeds from exercise of common stock options	2,540	2,743
Net cash provided by financing activities	<u>301,117</u>	<u>120,289</u>
Effect of exchange rate changes on cash	<u>(30)</u>	<u>22</u>
Increase in cash and cash equivalents	190,540	1,332
Cash and cash equivalents at beginning of year	15,627	16,055
Cash and cash equivalents at end of period	<u>\$ 206,167</u>	<u>\$ 17,387</u>

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

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

	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income	Common Stock in Treasury	Total
	Shares Issued	Amount					
	(in thousands)						
Balance at December 31, 2011	349,059	\$ 3,491	\$ 903,399	\$ 2,656,214	\$ 408,428	\$ (2,228)	\$ 3,969,304
Comprehensive income:							
Net income	—	—	—	107,704	—	—	107,704
Other comprehensive income	—	—	—	—	66,570	—	66,570
Total comprehensive income							174,274
Stock-based compensation	—	—	5,708	—	—	—	5,708
Exercise of stock options	189	1	2,539	—	—	—	2,540
Issuance of restricted stock	2	—	—	—	—	—	—
Cancellation of restricted stock	(23)	—	—	—	—	—	—
Treasury stock – non-qualified plan	—	—	—	—	—	(67)	(67)
Balance at March 31, 2012	<u>349,227</u>	<u>\$ 3,492</u>	<u>\$ 911,646</u>	<u>\$ 2,763,918</u>	<u>\$ 474,998</u>	<u>\$ (2,295)</u>	<u>\$ 4,151,759</u>

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

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

(1) BASIS OF PRESENTATION AND NEW ACCOUNTING STANDARDS

Southwestern Energy Company (including its subsidiaries, collectively, “Southwestern” or the “Company”) is an independent energy company 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.

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

In July 2011, the FASB issued Accounting Standards Update No. 2011-05, *Presentation of Comprehensive Income* (“Update 2011-05”), which amends Topic 200, *Comprehensive Income*. Update 2011-05 eliminates the option to present components of other comprehensive income (“OCI”) in the statement of changes in stockholders’ equity, and requires presentation of total comprehensive income and components of net income in a single statement of comprehensive income, or in two separate, consecutive statements. Update 2011-05 requires presentation of reclassification adjustments for items transferred from OCI to net income on the face of the financial statements where the components of net income and the components of OCI are presented. The amendments do not change current treatment of items in OCI, transfer of items from OCI, or reporting items in OCI net of the related tax impact. Update 2011-05 is effective for fiscal years and interim periods beginning after December 15, 2011. The Company early adopted all disclosure requirements of 2011-05 for the year-end December 31, 2011, except those items which were

deferred by Accounting Standards Update No. 2011-12, *Comprehensive Income (Topic 220): Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05*. The implementation of these changes did not have an impact on the Company's results of operations, financial position or cash flows.

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.

(2) DIVESTITURES

In May 2012, we sold certain oil and natural gas leases, wells and gathering equipment in East Texas for approximately \$175.0 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, are 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 23.0 MMcfe per day as of the closing date and our net proved reserves were approximately 138.0 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 March 31, 2012 and December 31, 2011 consisted of the following:

	March 31, 2012	December 31, 2011
	(in thousands)	
Prepaid drilling costs	\$ 55,948	\$ 42,775
Prepaid insurance	4,704	7,275
Total	<u>\$ 60,652</u>	<u>\$ 50,050</u>

(4) INVENTORY

Inventory recorded in current assets includes \$4.2 million at March 31, 2012 and \$7.8 million at December 31, 2011, for natural gas in underground storage owned by the Company's E&P segment, and \$33.1 million at March 31, 2012 and \$38.4 million at December 31, 2011, for tubulars and other equipment used in the E&P segment.

Other Assets include \$19.5 million at March 31, 2012 and 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 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 \$3.73 per MMBtu and \$94.65 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 did not exceed the ceiling amount and did not result in a ceiling test impairment at March 31, 2012. Cash flow hedges of natural gas production in place increased the ceiling value by \$303.2 million at March 31, 2012. Excluding the effect of cash flow hedges from the ceiling test at March 31, 2012 would have resulted in a \$213.9 million (net of taxes) ceiling test impairment. Decreases in market prices as well as changes in production rates, levels of reserves, evaluation of costs excluded from amortization, future development costs and production costs could result in future ceiling test impairments. Using the first-day-of-the-month prices of natural gas for the first five 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 are likely to require write-downs in each of the remaining quarters in 2012.

All of our costs directly associated with the acquisition and evaluation of properties in New Brunswick, Canada relating to our exploration program at March 31, 2012 were unproved and did not exceed the ceiling amount. If our exploration program in Canada is unsuccessful on all or a portion of these properties, a ceiling test impairment may result in the future.

(6) EARNINGS PER SHARE

The following table presents the computation of earnings per share for the three months ended March 31, 2012 and 2011:

	For the three months ended	
	March 31,	
	2012	2011
Net income attributable to Southwestern Energy (in thousands)	\$ 107,704	\$ 136,609
Number of common shares:		
Weighted average outstanding	348,000,074	346,833,906
Issued upon assumed exercise of outstanding stock options	1,889,691	2,700,902
Effect of issuance of nonvested restricted common stock	100,960	162,519
Weighted average and potential dilutive outstanding ⁽¹⁾	<u>349,990,725</u>	<u>349,697,327</u>
Earnings per share:		
Net income attributable to Southwestern Energy stockholders – basic	\$ 0.31	\$ 0.39
Net income attributable to Southwestern Energy stockholders – diluted	\$ 0.31	\$ 0.39

- (1) Options for 1,702,166 shares and 657,763 shares of restricted stock were excluded from the calculation for the three months ended March 31, 2012 because they would have had an antidilutive effect. Options for 843,324 shares and 4,928 shares of restricted stock were excluded from the calculation for the three months ended March 31, 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 March 31, 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:

<i>Fixed price swaps</i>	The Company receives a fixed price for the contract and pays a floating market price to the counterparty.
<i>Floating price swaps</i>	The Company receives a floating market price from the counterparty and pays a fixed price.
<i>Costless-collars</i>	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.
<i>Basis swaps</i>	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 March 31, 2012 and December 31, 2011:

	Derivative Assets			
	March 31, 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	\$ 437,974	Hedging asset	\$ 333,479
Costless-collars	Hedging asset	180,101	Hedging asset	179,080
Fixed and floating price swaps	Other assets	211,439	Other assets	201,081
Total derivatives designated as hedging instruments		<u>\$ 829,514</u>		<u>\$ 713,640</u>
Derivatives not designated as hedging instruments:				
Basis swaps	Hedging asset	\$ 2,636	Hedging asset	\$ 1,906
Basis swaps	Other assets	2,179	Other assets	1,797
Total derivatives not designated as hedging instruments		<u>\$ 4,815</u>		<u>\$ 3,703</u>
Total derivative assets		<u>\$ 834,329</u>		<u>\$ 717,343</u>
	Derivative Liabilities			
	March 31, 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 liability	\$ 14,341	Hedging liability	\$ 11,849
Costless-collars	Hedging liability	28	Hedging liability	209
Total derivatives designated as hedging instruments		<u>\$ 14,369</u>		<u>\$ 12,058</u>
Derivatives not designated as hedging instruments:				
Basis swaps	Hedging liability	\$ 209	Hedging liability	\$ 400
Basis swaps	Long-term hedging liability	136	Long-term hedging liability	55
Total derivatives not designated as hedging instruments		<u>\$ 345</u>		<u>\$ 455</u>
Total derivative liabilities		<u>\$ 14,714</u>		<u>\$ 12,513</u>

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 March 31, 2012, the Company had cash flow hedges on the following volumes of natural gas production (in Bcf):

Year	Fixed price swaps	Costless-collars
2012	139.2	60.5
2013	185.2	—

As of March 31, 2012, the Company recorded a net gain in accumulated other comprehensive income related to its hedging activities of \$490.7 million. This amount is net of a deferred income tax liability recorded as of March 31, 2012 of \$319.0 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 March 31, 2012 remain unchanged, the Company would expect to transfer an aggregate after-tax net gain of approximately \$363.6 million from accumulated other comprehensive income to earnings during the next 12 months. Gains or losses from derivative instruments designated as cash flow hedges are reflected as adjustments to gas sales in the unaudited condensed consolidated statements of operations. 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 months ended March 31, 2012 and 2011:

<u>Derivative Instrument</u>	Gain Recognized in Other Comprehensive Income (Effective Portion)	
	For the three months ended March 31,	
	2012	2011
	(in thousands)	
Fixed price swaps	\$ 218,957	\$ 9,069
Costless-collars	\$ 56,511	\$ 1,954

<u>Derivative Instrument</u>	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 March 31,	
		2012	2011
		(in thousands)	
Fixed price swaps	Gas Sales	\$ 106,311	\$ 36,801
Costless-collars	Gas Sales	\$ 55,310	\$ 15,098

<u>Derivative Instrument</u>	Classification of Gain (Loss) Recognized in Earnings (Ineffective Portion)	Gain (Loss) Recognized in Earnings (Ineffective Portion)	
		For the three months ended March 31,	
		2012	2011
		(in thousands)	
Fixed price swaps	Gas Sales	\$ 4,299	\$ (2,067)
Costless-collars	Gas Sales	\$ 911	\$ 2,161

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 March 31, 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 hedging liabilities, as applicable, and all realized and unrealized gains and losses related to these contracts are recognized

immediately in the unaudited condensed consolidated statements of operations as a component of gas sales.

As of March 31, 2012, the Company had basis swaps on natural gas production that did not qualify for hedge accounting treatment of 27.5 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 months ended March 31, 2012 and 2011:

<u>Derivative Instrument</u>	<u>Income Statement Classification of Unrealized Gain</u>	<u>Unrealized Gain Recognized in Earnings For the three months ended March 31,</u>	
		<u>2012</u>	<u>2011</u>
		(in thousands)	
Basis swaps	Gas Sales	\$ 1,223	\$ 906

<u>Derivative Instrument</u>	<u>Income Statement Classification of Realized Gain (Loss)</u>	<u>Realized Gain (Loss) Recognized in Earnings For the three months ended March 31,</u>	
		<u>2012</u>	<u>2011</u>
		(in thousands)	
Basis swaps	Gas Sales	\$ 1,018	\$ (2,256)

(8) FAIR VALUE MEASUREMENTS

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

	<u>March 31, 2012</u>		<u>December 31, 2011</u>	
	<u>Carrying Amount</u>	<u>Fair Value</u>	<u>Carrying Amount</u>	<u>Fair Value</u>
	(in thousands)			
Cash and cash equivalents	\$ 206,167	\$ 206,167	\$ 15,627	\$ 15,627
Unsecured revolving credit facility	\$ —	\$ —	\$ 671,500	\$ 671,500
Senior notes	\$ 1,670,580	\$ 1,802,255	\$ 671,800	\$ 773,578
Derivative instruments	\$ 819,615	\$ 819,615	\$ 704,830	\$ 704,830

The carrying values of cash and cash equivalents, 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 3.5% at March 31, 2012 and 4.6% at December 31, 2011, and 4.10% Senior Notes due 2022, which was 4.2% at March 31, 2012. As such, we consider the fair value of our senior notes to be a Level 1 measurement on the fair value hierarchy. The carrying value of the borrowings under the Company's unsecured revolving credit facility at December 31, 2011 approximate fair value.

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

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

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

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

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

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

The accounting group, reporting to the Chief Accounting Officer, is responsible for the accounting for 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):

March 31, 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	\$ —	\$ 649,413	\$ 184,916	\$ 834,329
Derivative liabilities	—	(14,341)	(373)	(14,714)
Total	<u>\$ —</u>	<u>\$ 635,072</u>	<u>\$ 184,543</u>	<u>\$ 819,615</u>
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	<u>\$ —</u>	<u>\$ 522,711</u>	<u>\$ 182,119</u>	<u>\$ 704,830</u>

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-month periods ended March 31, 2012 and March 31, 2011. The fair values of Level 3 derivative instruments are estimated using proprietary valuation models that utilize both market observable and unobservable parameters. Level 3 instruments presented in the table consist of net derivatives valued using pricing models incorporating assumptions that, in the Company's judgment, reflect the assumptions a marketplace participant would have used at March 31, 2012.

	For the three months ended	
	March 31,	
	2012	2011
	(in thousands)	
Balance at beginning of period	\$ 182,119	\$ 97,677
Total gains or losses (realized/unrealized):		
Included in earnings	58,462	15,910
Included in other comprehensive income	290	(15,306)
Purchases, issuances, and settlements:		
Purchases	—	—
Issuances	—	—
Settlements	(56,328)	(12,843)
Transfers into/out of Level 3	—	142
Balance at end of period	<u>\$ 184,543</u>	<u>\$ 85,580</u>
Change in unrealized gains (losses) included in earnings relating to derivatives still held as of March 31	<u>\$ 2,134</u>	<u>\$ 3,067</u>

(9) DEBT

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

	March 31,	December 31,
	2012	2011
	(in thousands)	
Short-term debt:		
7.15% Senior Notes due 2018	\$ 1,200	\$ 1,200
Total short-term debt	<u>1,200</u>	<u>1,200</u>
Long-term debt:		
Variable rate (2.276% at December 31, 2011) unsecured revolving credit facility, expires February 2016	—	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	30,600	30,600
4.10% Senior Notes due 2022	1,000,000	—
Unamortized discount	(1,220)	—
Total long-term debt	<u>1,669,380</u>	<u>1,342,100</u>
Total debt	<u>\$ 1,670,580</u>	<u>\$ 1,343,300</u>

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 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 for freely tradeable notes with identical terms on or prior to the 270th calendar day after issuance and to cause a shelf registration statement to become effective for resales. 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 amended credit facility is calculated based upon our debt rating and is currently 200 basis points over the current London Interbank Offered Rate (LIBOR) and was 200 basis points over LIBOR at March 31, 2012. The Credit Facility is guaranteed by the Company’s subsidiary, SEECO. The Credit Facility requires additional subsidiary guarantors if certain guaranty coverage levels are not satisfied. The revolving credit facility contains covenants which impose certain restrictions on the Company. Under the credit agreement, the Company may not issue total debt in excess of 60% of its total capital and must maintain a ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) to interest expense of 3.5 or above. The terms of the Credit Facility also include covenants that restrict the ability of the Company and its material subsidiaries to merge, consolidate or sell all or substantially all of their assets, restrict the ability of the Company and its subsidiaries to incur liens and restrict the ability of the Company’s subsidiaries to incur indebtedness. At March 31, 2012, the Company’s capital structure consisted of 29% debt and 71% equity and it was in compliance with the covenants of its debt agreements. While the Company believes all of the lenders under the Credit Facility have the ability to provide funds, it cannot predict whether each will be able to meet its obligation under the facility.

(10) COMMITMENTS AND CONTINGENCIES

Commitments

In the first quarter of 2010, the Company was awarded exclusive licenses by the Province of New Brunswick in Canada to conduct an exploration program covering approximately 2.5 million acres in the province. The licenses require the Company to make certain capital investments in New Brunswick of approximately \$47 million Canadian dollars (“CAD”) in the aggregate over a three year period. In order to obtain the licenses, the Company provided promissory notes payable on demand to the Minister of Finance of the Province of New Brunswick with an aggregate principal amount of CAD \$44.5 million. The promissory notes secure the Company's capital expenditure obligations under the licenses and are returnable to the Company to the extent the Company performs such obligations. If the Company fails to fully perform, the Minister of Finance may retain a portion of the applicable promissory notes in an amount equal to any deficiency. The Company commenced its Canada exploration program in 2010 and no liability has been recognized in connection with the promissory notes due to the Company's investments in New Brunswick as of March 31, 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.

The Company's subsidiaries, 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 March 31, 2012, SES and SEPCO's aggregate obligations under gathering agreements and firm transportation agreements (including precedent agreements assuming completion of the pipeline projects) for the Marcellus Shale operations totaled approximately \$1.2 billion and the Company has guarantee obligations of up to \$100 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 million as well as other remedies, including special damages and punitive damages of four times the amount of actual damages established at trial.

Immediately before the commencement of the trial in November 2010, plaintiff was permitted, over SEPCO's objections, to file a Seventh Amended Petition claiming actual damages of \$46 million and also seeking the equitable remedy of disgorgement of all profits for the misappropriation of trade secrets and the breach of fiduciary duty claims. In December 2010, the jury found in favor of the plaintiff with respect to all of the statutory and common law claims and awarded \$11.4 million in compensatory damages. The jury did not, however, award the plaintiff any special, punitive or other damages. In addition, the jury separately determined that SEPCO's profits for purposes of disgorgement were \$381.5 million. This profit determination does not constitute a judgment or an award. The plaintiff's

entitlement to disgorgement of profits as an equitable remedy will be determined by the judge and it is within the judge's discretion to award none, some or all the amount of profit to the plaintiff. On December 31, 2010, the plaintiff filed a motion to enter the judgment based on the jury's verdict. On February 11, 2011, SEPCO filed a motion for a judgment notwithstanding the verdict and a motion to disregard certain findings. On March 11, 2011, the plaintiff filed an amended motion for judgment and intervenor filed its motion for judgment seeking not only the monetary damages and the profits determined by the jury but also seeking, as a new remedy, a constructive trust for profits from 143 wells as well as future drilling and sales of properties in the prospect areas. A hearing on the post-verdict motions was held on March 14, 2011. At the suggestion of the judge, all parties voluntarily agreed to participate in non-binding mediation efforts. The mediation occurred on April 6, 2011 and was unsuccessful. On June 6, 2011, SEPCO received by mail a letter dated June 2, 2011 from the judge, in which he made certain rulings with respect to the post-verdict motions and responses filed by the parties. In his rulings, the judge denied SEPCO's motion for judgment, judgment notwithstanding the verdict and to disregard certain findings. Plaintiff's and intervenor's claim for a constructive trust was denied but the judge ruled that plaintiff and intervenor shall recover from SEPCO \$11.4 million and a reasonable attorney's fee of 40% of the total damages awarded and are entitled to recover on their claim for disgorgement. The judge instructed that SEPCO calculate the profit on the designated wells for each respective period. SEPCO performed the calculation and provided it to the judge in June 2011. On July 5, 2011, plaintiff and intervenor filed a letter with the court raising objections to the accounting provided by SEPCO, to which SEPCO filed a response on July 11, 2011. On July 12, 2011, the judge sent a letter to the parties in which he ruled that after reviewing the parties' respective position letters, he was awarding \$23.9 million in disgorgement damages in favor of the plaintiff and intervenor. In the July 12, 2011 letter, the judge instructed the plaintiff and intervenor to prepare a judgment for his approval prior to July 21, 2011 consistent with his findings in his June 2, 2011 letter and the disgorgement award. 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.

The Company believes that SEPCO has a number of legal grounds for appealing the judgment, all of which will be vigorously pursued. Based on the Company's understanding and judgment of the facts and merits of this case, including appellate defenses, and after considering the advice of counsel, the Company has determined that, although reasonably possible after exhaustion of all appeals, an adverse final outcome to this lawsuit is not probable. As such, the Company has not accrued any amounts with respect to this lawsuit. If the plaintiff and intervenor were to ultimately prevail in the appellate process, the Company currently estimates, based on the 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. The Company has not accrued any amounts with respect to this lawsuit and cannot reasonably estimate the amount of any potential liability based on the Company's understanding and judgment of the facts and merits of this case.

In March 2010, the Company's subsidiary, SEECO, Inc., was served with a subpoena from a federal grand jury in Little Rock, Arkansas. Based on the documents requested under the subpoena and subsequent discussions described below, the Company believes the grand jury is investigating matters involving approximately 27 horizontal wells operated by SEECO in Arkansas, including whether appropriate leases or permits were obtained therefor and whether royalties and other production attributable to federal lands have been properly accounted for and paid. The Company believes it has fully complied with all requests related to the federal subpoena and delivered its affidavit to that effect.

The Company and representatives of the Bureau of Land Management and the U.S. Attorney have had discussions since the production of the documents pursuant to the subpoena. In January 2011, the Company voluntarily produced additional materials informally requested by the government arising from these discussions. Although, to the Company's knowledge, no proceeding in this matter has been initiated against SEECO, the Company cannot predict whether or when one might be initiated. The Company intends to fully comply with any further requests and to cooperate with any related investigation. No assurance can be made as to the time or resources that will need to be devoted to this inquiry or the impact of the final outcome of the discussions or any related proceeding.

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 or our results of operations 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 March 31,	
	2012	2011
	(in thousands)	
Cash paid during the year for interest	\$ 26,452	\$ 24,857
Cash paid during the year for income taxes	68	16,000
Increase in noncash property additions	17,569	4,129

(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 months ended March 31, 2012 and 2011:

	Pension Benefits	
	For the three months ended March 31,	
	2012	2011
	(in thousands)	
Service cost	\$ 2,736	\$ 2,331
Interest cost	1,013	917
Expected return on plan assets	(1,357)	(1,099)
Amortization of prior service cost	71	86
Amortization of net loss	305	214
Net periodic benefit cost	<u>\$ 2,768</u>	<u>\$ 2,449</u>

	Other Postretirement Benefits	
	For the three months ended March 31,	
	2012	2011
	(in thousands)	
Service cost	\$ 458	\$ 338
Interest cost	100	63
Amortization of transition obligation	16	16
Amortization of prior service cost	3	4
Amortization of net loss	23	3
Net periodic benefit cost	<u>\$ 600</u>	<u>\$ 424</u>

The Company currently expects to contribute \$16.2 million to its pension plans and \$0.1 million to its postretirement benefit plan in 2012. As of March 31, 2012, the Company has contributed \$3.0 million to the pension plans and less than \$0.1 million to the postretirement benefit plan.

The Company maintains a non-qualified deferred compensation supplemental retirement savings plan ("Non-Qualified Plan") for certain key employees who may elect to defer and contribute a portion of their compensation, as permitted by the plan. Shares of the Company's common stock purchased under the terms of the Non-Qualified Plan are presented as treasury stock and totaled 100,970 shares at March 31, 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 months ended March 31, 2012 and 2011:

	For the three months ended March 31,	
	2012	2011
	(in thousands)	
Stock-based compensation cost – expensed	\$ 2,844	\$ 2,450
Stock-based compensation cost – capitalized	2,864	1,910

As of March 31, 2012, there was \$48.3 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 2.7 years.

The following table summarizes stock option activity for the first three months of 2012 and provides information for options outstanding as of March 31, 2012.

	Number of Options	Weighted Average Exercise Price
Outstanding at December 31, 2011	4,741,732	\$ 21.24
Granted	5,300	32.27
Exercised	(189,475)	13.41
Forfeited or expired	(16,976)	37.74
Outstanding at March 31, 2012	<u>4,540,581</u>	<u>\$ 21.52</u>
Exercisable at March 31, 2012	<u>3,322,436</u>	<u>\$ 15.84</u>

The following table summarizes restricted stock activity for the three months ended March 31, 2012 and provides information for unvested shares as of March 31, 2012.

	Number of Shares	Weighted Average Grant Date Fair Value
Unvested shares at December 31, 2011	1,019,737	\$ 36.71
Granted	4,689	32.35
Vested	(14,868)	36.72
Forfeited	(22,745)	37.46
Unvested shares at March 31, 2012	<u>986,813</u>	<u>\$ 36.70</u>

(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 and expenses. Income before income taxes, for the purpose of reconciling the operating income amount shown below to consolidated income before income taxes, is the sum of operating income, interest expense and 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)			
<u>Three months ended March 31, 2012:</u>				
Revenues from external customers	\$ 466,265	\$ 190,173	\$ 31	\$ 656,469
Intersegment revenues	713	356,281	819	357,813
Operating income	116,243	69,289	428	185,960
Other income (loss) ⁽¹⁾	(183)	(18)	1	(200)
Depreciation, depletion and amortization expense	182,739	10,570	318	193,627
Interest expense ⁽¹⁾	3,322	3,667	349	7,338
Provision for income taxes ⁽¹⁾	44,838	25,848	32	70,718
Assets	7,038,247	1,087,020	428,894 ⁽²⁾	8,554,161
Capital investments ⁽³⁾	533,139	26,164	13,809	573,112
<u>Three months ended March 31, 2011:</u>				
Revenues from external customers	\$ 470,656	\$ 205,679	\$ —	\$ 676,335
Intersegment revenues	5,514	473,589	776	479,879
Operating income	178,283	53,917	451	232,651
Other income ⁽¹⁾	343	29	2	374
Depreciation, depletion and amortization expense	154,810	8,391	246	163,447
Interest expense ⁽¹⁾	2,904	4,532	—	7,436
Provision for income taxes ⁽¹⁾	69,382	19,420	178	88,980
Assets	5,134,657	1,025,072	181,019 ⁽²⁾	6,340,748
Capital investments ⁽³⁾	468,212	45,978	16,339	530,529

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

(2) Other assets represent corporate assets not allocated to segments and assets, including investments in cash equivalents, for non-reportable segments.

(3) Capital investments include increases of \$15.3 million and \$1.5 million for the three months ended March 31, 2012 and 2011, respectively, relating to the change in accrued expenditures between periods.

Included in intersegment revenues of the Midstream Services segment are \$286.1 million and \$411.2 million for the three months ended March 31, 2012 and 2011, respectively, for marketing of the Company's E&P sales. Corporate assets include cash and cash equivalents, furniture and fixtures, prepaid debt and other costs. Corporate general and administrative costs, depreciation expense and taxes other than income are allocated to the segments. For the three months ended March 31, 2012 and 2011, capital investments within the E&P segment include \$2.4 million related to the Company's activities in Canada. At March 31, 2012 and at March 31, 2011, assets include \$31.3 million and \$13.7 million, respectively, 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 guarantors (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 (in thousands)	Eliminations	Consolidated
<u>Three months ended March 31, 2012:</u>					
Operating revenues	\$ —	\$ 614,445	\$ 113,125	\$ (71,101)	\$ 656,469
Operating costs and expenses:					
Gas purchases – midstream services	—	146,903	—	(227)	146,676
Operating expenses	—	103,056	27,981	(70,079)	60,958
General and administrative expenses	—	41,708	7,913	(795)	48,826
Depreciation, depletion and amortization	—	182,837	10,790	—	193,627
Taxes, other than income taxes	—	16,998	3,424	—	20,422
Total operating costs and expenses	—	491,502	50,108	(71,101)	470,509
Operating income	—	122,943	63,017	—	185,960
Other loss, net	—	(174)	(26)	—	(200)
Equity in earnings of subsidiaries	107,704	—	—	(107,704)	—
Interest expense	—	3,755	3,583	—	7,338
Income (loss) before income taxes	107,704	119,014	59,408	(107,704)	178,422
Provision for income taxes	—	46,892	23,826	—	70,718
Net income (loss) attributable to Southwestern Energy	\$ 107,704	\$ 72,122	\$ 35,582	\$ (107,704)	\$ 107,704
Other comprehensive income	254	65,835	481	—	66,570
Comprehensive income (loss)	\$ 107,958	\$ 137,957	\$ 36,063	\$ (107,704)	\$ 174,274
<u>Three months ended March 31, 2011:</u>					
Operating revenues	\$ —	\$ 641,843	\$ 93,658	\$ (59,166)	\$ 676,335
Operating costs and expenses:					
Gas purchases – midstream services	—	170,582	—	(352)	170,230
Operating expenses	—	86,852	27,984	(58,038)	56,798
General and administrative expenses	—	32,044	5,849	(776)	37,117
Depreciation, depletion and amortization	—	154,401	9,046	—	163,447
Taxes, other than income taxes	—	13,907	2,185	—	16,092
Total operating costs and expenses	—	457,786	45,064	(59,166)	443,684
Operating income	—	184,057	48,594	—	232,651
Other income, net	—	345	29	—	374
Equity in earnings of subsidiaries	136,609	—	—	(136,609)	—
Interest expense	—	3,645	3,791	—	7,436
Income (loss) before income taxes	136,609	180,757	44,832	(136,609)	225,589
Provision for income taxes	—	71,362	17,618	—	88,980
Net income (loss) attributable to Southwestern Energy	\$ 136,609	\$ 109,395	\$ 27,214	\$ (136,609)	\$ 136,609
Other comprehensive income (loss)	197	(24,992)	262	—	(24,533)
Comprehensive income (loss)	\$ 136,806	\$ 84,403	\$ 27,476	\$ (136,609)	\$ 112,076

CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

	<u>Parent</u>	<u>Guarantors</u>	<u>Non- Guarantors</u> (in thousands)	<u>Eliminations</u>	<u>Consolidated</u>
<u>March 31, 2012:</u>					
ASSETS					
Cash and cash equivalents	\$ 205,415	\$ 489	\$ 263	\$ —	\$ 206,167
Accounts receivable	2,940	260,402	35,974	—	299,316
Inventories	—	36,408	915	—	37,323
Other current assets	4,703	679,271	1,627	—	685,601
Total current assets	<u>213,058</u>	<u>976,570</u>	<u>38,779</u>	<u>—</u>	<u>1,228,407</u>
Intercompany receivables	2,068,919	41	22,329	(2,091,289)	—
Property and equipment	194,097	10,271,762	1,178,095	—	11,643,954
Less: Accumulated depreciation, depletion and amortization	61,540	4,405,113	151,229	—	4,617,882
	<u>132,557</u>	<u>5,866,649</u>	<u>1,026,866</u>	<u>—</u>	<u>7,026,072</u>
Investments in subsidiaries (equity method)	3,433,064	—	—	(3,433,064)	—
Other assets	36,212	240,120	23,350	—	299,682
Total assets	<u>\$ 5,883,810</u>	<u>\$ 7,083,380</u>	<u>\$ 1,111,324</u>	<u>\$ (5,524,353)</u>	<u>\$ 8,554,161</u>
LIABILITIES AND EQUITY					
Accounts and notes payable	\$ 96,277	\$ 430,906	\$ 48,857	\$ —	\$ 576,040
Other current liabilities	13,033	370,224	1,347	—	384,604
Total current liabilities	<u>109,310</u>	<u>801,130</u>	<u>50,204</u>	<u>—</u>	<u>960,644</u>
Intercompany payables	—	1,728,162	363,127	(2,091,289)	—
Long-term debt	1,669,380	—	—	—	1,669,380
Deferred income taxes	(96,880)	1,492,017	265,147	—	1,660,284
Other liabilities	50,241	56,198	5,655	—	112,094
Total liabilities	<u>1,732,051</u>	<u>4,077,507</u>	<u>684,133</u>	<u>(2,091,289)</u>	<u>4,402,402</u>
Commitments and contingencies					
Total equity	<u>4,151,759</u>	<u>3,005,873</u>	<u>427,191</u>	<u>(3,433,064)</u>	<u>4,151,759</u>
Total liabilities and equity	<u>\$ 5,883,810</u>	<u>\$ 7,083,380</u>	<u>\$ 1,111,324</u>	<u>\$ (5,524,353)</u>	<u>\$ 8,554,161</u>

CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

	Parent	Guarantors	Non- Guarantors (in thousands)	Eliminations	Consolidated
<u>December 31, 2011:</u>					
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	<u>23,712</u>	<u>917,933</u>	<u>36,633</u>	<u>—</u>	<u>978,278</u>
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
	<u>123,046</u>	<u>5,511,739</u>	<u>1,010,695</u>	<u>—</u>	<u>6,645,480</u>
Investments in subsidiaries (equity method)	3,256,195	—	—	(3,256,195)	—
Other assets	28,641	227,152	23,346	—	279,139
Total assets	<u>\$ 5,484,726</u>	<u>\$ 6,656,877</u>	<u>\$ 1,094,191</u>	<u>\$ (5,332,897)</u>	<u>\$ 7,902,897</u>
LIABILITIES AND EQUITY					
Accounts and notes payable	\$ 206,541	\$ 332,710	\$ 37,276	\$ —	\$ 576,527
Other current liabilities	4,712	301,170	2,504	—	308,386
Total current liabilities	<u>211,253</u>	<u>633,880</u>	<u>39,780</u>	<u>—</u>	<u>884,913</u>
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	<u>1,515,422</u>	<u>3,760,032</u>	<u>734,841</u>	<u>(2,076,702)</u>	<u>3,933,593</u>
Commitments and contingencies					
Total equity	<u>3,969,304</u>	<u>2,896,845</u>	<u>359,350</u>	<u>(3,256,195)</u>	<u>3,969,304</u>
Total liabilities and equity	<u>\$ 5,484,726</u>	<u>\$ 6,656,877</u>	<u>\$ 1,094,191</u>	<u>\$ (5,332,897)</u>	<u>\$ 7,902,897</u>

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Unaudited)

	Parent	Guarantors	Non-Guarantors (in thousands)	Eliminations	Consolidated
<u>Three months ended March 31, 2012:</u>					
Net cash provided by (used in) operating activities	\$ (66,501)	\$ 428,743	\$ 82,421	\$ —	\$ 444,663
Investing activities:					
Capital investments	(15,673)	(502,036)	(39,922)	—	(557,631)
Proceeds from sale of property and equipment	—	651	—	—	651
Other	4,085	(9,440)	7,125	—	1,770
Net cash used in investing activities	(11,588)	(510,825)	(32,797)	—	(555,210)
Financing activities:					
Intercompany activities	(32,324)	82,571	(50,247)	—	—
Payments on revolving long-term debt	(1,271,300)	—	—	—	(1,271,300)
Borrowings under revolving long-term debt	599,800	—	—	—	599,800
Proceeds from issuance of long-term debt	998,780	—	—	—	998,780
Other items	(26,163)	—	—	—	(26,163)
Net cash provided by (used in) financing activities	268,793	82,571	(50,247)	—	301,117
Effect of exchange rate changes on cash	—	—	(30)	—	(30)
Increase (decrease) in cash and cash equivalents	190,704	489	(653)	—	190,540
Cash and cash equivalents at beginning of year	14,711	—	916	—	15,627
Cash and cash equivalents at end of period	\$ 205,415	\$ 489	\$ 263	\$ —	\$ 206,167
<u>Three months ended March 31, 2011:</u>					
Net cash provided by (used in) operating activities	\$ (26,284)	\$ 359,234	\$ 63,529	\$ —	\$ 396,479
Investing activities:					
Capital investments	(15,533)	(469,341)	(41,265)	—	(526,139)
Proceeds from sale of property and equipment	—	11,056	—	—	11,056
Other	3,574	(6,100)	2,151	—	(375)
Net cash used in investing activities	(11,959)	(464,385)	(39,114)	—	(515,458)
Financing activities:					
Intercompany activities	(75,684)	99,515	(23,831)	—	—
Payments on revolving long-term debt	(782,800)	—	—	—	(782,800)
Borrowings under revolving long-term debt	892,700	—	—	—	892,700
Other items	10,389	—	—	—	10,389
Net cash provided by (used in) financing activities	44,605	99,515	(23,831)	—	120,289
Effect of exchange rate changes on cash	—	—	22	—	22
Increase (decrease) in cash and cash equivalents	6,362	(5,636)	606	—	1,332
Cash and cash equivalents at beginning of year	8,381	7,631	43	—	16,055
Cash and cash equivalents at end of period	\$ 14,743	\$ 1,995	\$ 649	\$ —	\$ 17,387

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-month periods ended March 31, 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 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 through the drillbit. We derive the vast majority of our operating income and cash flow from the natural gas production of our E&P business and expect this to continue in the future. We expect that growth in our operating income and revenues will primarily depend on natural gas prices and our ability to increase our natural gas production. We expect our natural gas production volumes will continue to increase due to the ongoing development of 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.

Recent Financial and Operating Results

We reported net income of \$107.7 million for the three months ended March 31, 2012, or \$0.31 diluted share, compared to net income of \$136.6 million, or \$0.39 per diluted share, for the comparable period in 2011.

Our natural gas and oil production increased to 133.4 Bcfe for the three months ended March 31, 2012, up 18.4 Bcfe or 16%, from 115.0 Bcfe for the three months ended March 31, 2011. The increase in our first quarter 2012 production was primarily due to a 14.7 Bcf increase in net production from our Fayetteville Shale play and a 6.5 Bcf

increase from our Marcellus Shale properties, which more than offset a combined 2.8 Bcfe decrease in net production from our East Texas and Arkoma Basin properties. The average price realized for our natural gas production, including the effects of hedges, decreased approximately 15% to \$3.49 per Mcf for the three months ended March 31, 2012, as compared to the same period in 2011.

Operating income from our E&P segment was \$116.2 million for the three months ended March 31, 2012, down from \$178.3 million for the same period in 2011. Operating income decreased as the revenue impact of our 16% increase in production was more than offset by the 15% decline in our average realized gas prices and a \$52.8 million increase in operating costs and expenses that resulted from our production growth.

Operating income for our Midstream Services segment was \$69.3 million for the three months ended March 31, 2012, up from \$53.9 million for the three months ended March 31, 2011, due to an increase of \$19.6 million in gas gathering revenues, which were partially offset by a \$5.6 million increase in operating costs and expenses, exclusive of gas purchase costs, that resulted from our growth in volumes gathered. Volumes gathered grew to 202.0 Bcf for the three months ended March 31, 2012 compared to 171.5 Bcf for the same period in 2011.

Capital investments were \$573.1 million for the three months ended March 31, 2012, of which \$533.1 million was invested in our E&P segment, compared to total capital investments of \$530.5 million for the same period of 2011, of which \$468.2 million was invested in our E&P segment.

Recent Developments

Pennsylvania Impact Fee

In February 2012, the Commonwealth of Pennsylvania passed the Unconventional Gas Well Impact Fee Act (Act 13), which amends Title 58 (Oil and Gas) of the Pennsylvania Consolidated Statutes. The legislation, which covers all of Southwestern's Marcellus Shale acreage, imposes an annual impact fee for a period of up to fifteen years on each natural gas well drilled. The impact fee adjusts annually based on the age of the well, the average NYMEX natural gas price for the year and an inflation index. As a result of this legislation, Southwestern recorded a one time expense in Taxes, other than income taxes in the first quarter of 2012 of \$3.2 million based on the required retroactive application of this legislation to all wells drilled in 2011 and previous years.

Private Placement of \$1 Billion of Senior Notes

In March 2012, the Company 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 will be used for general corporate purposes.

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 \$175.0 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, are 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 23.0 MMcfe per day as of the closing date and our net proved reserves were approximately 138.0 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 March 31,	
	2012	2011
Revenues (in thousands)	\$ 466,978	\$ 476,170
Operating costs and expenses (in thousands)	\$ 350,735	\$ 297,887
Operating income (in thousands)	\$ 116,243	\$ 178,283
Gas production (Bcf)	133.3	114.9
Oil production (MBbls)	24	30
Total production (Bcfe)	133.4	115.0
Average gas price per Mcf, including hedges	\$ 3.49	\$ 4.12
Average gas price per Mcf, excluding hedges	\$ 2.24	\$ 3.68
Average oil price per Bbl	\$ 104.39	\$ 92.11
Average unit costs per Mcfe:		
Lease operating expenses	\$ 0.83	\$ 0.86
General & administrative expenses	\$ 0.30	\$ 0.26
Taxes, other than income taxes	\$ 0.13	\$ 0.12
Full cost pool amortization	\$ 1.33	\$ 1.31

Revenues

Revenues for our E&P segment were down \$9.2 million, or 2%, for the three months ended March 31, 2012 compared to the same period in 2011. Higher natural gas production volumes in the first quarter of 2012 increased revenues by \$75.7 million while lower realized prices for our natural gas production decreased revenue by \$83.0 million. We expect our natural gas production volumes to continue to increase due to the development of our Fayetteville Shale play in Arkansas and our Marcellus Shale properties in Pennsylvania. Natural gas and oil prices are difficult to predict and subject to wide price fluctuations. As of May 1, 2012, we had hedged 199.7 Bcf of our remaining 2012 natural gas production and 185.2 Bcf of our 2013 natural 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 March 31, 2012 our natural gas and oil production increased 16% to 133.4 Bcfe, up from 115.0 Bcfe for the same period in 2011, and was produced entirely by our properties in the United States. The 18.4 Bcfe increase in our 2012 production was primarily due to a 14.7 Bcf increase in net production from our Fayetteville Shale play and a 6.5 Bcf increase in net production from our Marcellus Shale properties, which was partially offset by a combined 2.8 Bcfe decrease in net production from our East Texas and Arkoma Basin properties. Natural gas production represented nearly 100% of our total production for the three months ended March 31, 2012 and was up approximately 16% to 133.3 Bcf compared to the same period in 2011. Net production from the Fayetteville Shale and Marcellus Shale properties was 115.8 Bcf and 9.3 Bcf, respectively, for the three months ended March 31, 2012 compared to 101.1 Bcf and 2.8 Bcf for the same period in 2011.

Commodity Prices

The average price realized for our natural gas production, including the effects of hedges, decreased \$0.63, or 15%, per Mcf to \$3.49 per Mcf for the three months ended March 31, 2012, as compared to the same period in 2011. The decrease was the result of a \$1.44 Mcf decrease in average natural gas prices, excluding hedges, which was partially offset by a \$0.81 Mcf increased effect of our price hedging activities. Our hedging activities increased the average natural gas price \$1.25 per Mcf for the three months ended March 31, 2012 compared to an increase of \$0.44 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 three months ended March 31, 2012 of \$2.24 per Mcf was approximately \$0.50 lower than the average monthly NYMEX settlement price, primarily due to locational basis differentials and transportation costs. We had protected approximately 53% of our natural gas production for the three months ended March 31, 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 \$0.50 to \$0.55 per Mcf. At March 31, 2012 we had basis protected on approximately 187 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 \$0.02 per Mcf, excluding transportation and fuel charges. Additionally, at March 31, 2012, we had basis protected on approximately 64 Bcf of our 2013 expected natural gas production and 24 Bcf of our 2014 expected natural gas production through financial hedging activities and physical sales arrangements.

In addition to the basis hedges discussed above, at March 31, 2012, we had NYMEX fixed price hedges in place on notional volumes of 139.2 Bcf of our remaining 2012 natural gas production at an average price of \$5.02 per MMBtu and collars in place on notional volumes of 60.5 Bcf of our remaining 2012 natural gas production at an average floor and ceiling price of \$5.50 and \$6.67 per MMBtu, respectively.

As of March 31, 2012, we had NYMEX fixed price hedges in place on notional volumes of 185.2 Bcf of our 2013 natural gas production.

Operating Income

Operating income from our E&P segment was \$116.2 million for the three months ended March 31, 2012, compared to operating income of \$178.3 million for the same period in 2011. The decrease in operating income was the result of the revenue impact of our 16% growth in production which was more than offset by the 15% decline in our average realized natural gas prices and a \$52.8 million increase in operating costs and expenses that resulted from our production growth.

Operating Costs and Expenses

Lease operating expenses per Mcfe for our E&P segment were \$0.83 for three months ended March 31, 2012 compared to \$0.86 for the same period in 2011. The decrease in lease operating expenses per unit of production for the three month period ended March 31, 2012 as compared to the same period of 2011, is primarily due to decreased compression costs.

General and administrative expenses per Mcfe were \$0.30 for the three months ended March 31, 2012 compared to \$0.26 per Mcfe for the same period in 2011. In total, general and administrative expenses for our E&P segment were \$39.9 million for the three months ended March 31, 2012 compared to \$30.5 million for the same period in 2011. The increases in general and administrative expenses were primarily a result of increased payroll, incentive compensation, employee-related costs and information system costs associated with the expansion of our E&P operations due to the continued development of the Fayetteville Shale play and Marcellus Shale play.

Taxes other than income taxes per Mcfe increased to \$0.13 for the three months ended March 31, 2012 compared to \$0.12 for the same period in 2011, reflecting the new Pennsylvania natural gas impact fee covering all of our Marcellus Shale acreage. Taxes other than income taxes per Mcfe vary from period to period due to changes in severance and ad valorem taxes that result from the mix of our production volumes and fluctuations in commodity prices.

Our full cost pool amortization rate averaged \$1.33 per Mcfe for the three months ended March 31, 2012 compared to \$1.31 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 five 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 are likely to require write-downs in each of the remaining quarters in 2012.

Unevaluated costs excluded from amortization were \$1,128.5 million at March 31, 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 undeveloped leasehold acreage, seismic costs, and our wells in progress. Unevaluated costs excluded from amortization at March 31, 2012 included \$30.8 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 and revisions could have a material adverse impact on our per unit costs.

Midstream Services

	For the three months ended March 31,	
	2012	2011
(in thousands, except volumes)		
Revenues – marketing	\$ 434,277	\$ 586,648
Revenues – gathering	\$ 112,177	\$ 92,620
Gas purchases – marketing	\$ 425,495	\$ 579,320
Operating costs and expenses	\$ 51,670	\$ 46,031
Operating income	\$ 69,289	\$ 53,917
Gas volumes marketed (Bcf)	159.5	143.0
Gas volumes gathered (Bcf)	202.0	171.5

Revenues

Revenues from our marketing activities were down 26% to \$434.3 million for the three months ended March 31, 2012 compared to the same period in 2011. The decrease in marketing revenues resulted from a decrease in the prices received for volumes marketed, partially offset by an increase in the volumes marketed. For the three months ended March 31, 2012, the volumes marketed increased 12% and the price received for volumes marketed decreased 17% 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% and 94% of the marketed volumes for the three months ended March 31, 2012 and 2011, respectively.

Revenues from our gathering activities were up 21% to \$112.2 million for the three months ended March 31, 2012 compared to the same period in 2011. The increase in gathering revenues resulted primarily from an 18% increase in gas volumes gathered for the three months ended March 31, 2012 compared to the same period in 2011. Substantially all of the increases in gathering revenues for the three months ended March 31, 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 as expected.

Operating Income

Operating income from our Midstream Services segment increased to \$69.3 million for the three months ended March 31, 2012 compared to \$53.9 million for the same period in 2011. The increase in operating income reflects the substantial increases in natural gas volumes gathered which primarily resulted from our increased E&P production volumes. The \$15.4 million increase in operating income for the three months ended March 31, 2012 was primarily due to a \$19.6 million increase in gathering revenues which was partially offset by an increase in operating costs and expenses of \$5.6 million that resulted from our growth in volumes gathered. The remaining changes in operating income were due to changes in the margin generated by our natural gas marketing activities. Marketing margin increased \$1.5 million for the three months ended March 31, 2012 compared to the respective periods of 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, decreased to \$7.3 million for the three months ended March 31, 2012, compared to \$7.4 million for the same period in 2011. Interest expense, excluding capitalization, increased due primarily to our increased borrowing level. We capitalized interest of \$13.4 million for the three months ended March 31, 2012 compared to \$9.1 million for the same period in 2011. The increase in capitalized interest was primarily due to the increase in our costs excluded from amortization in our E&P segment.

Income Taxes

Our effective tax rates were 39.6% and 39.4% for the three months ended March 31, 2012 and 2011, respectively. For the three months ended March 31, 2012, we recorded an income tax expense of \$70.7 million compared to an income tax expense of \$89.0 million for the same period in 2011.

Stock-Based Compensation Expense

We recognized expense of \$2.8 million and capitalized \$2.9 million for stock-based compensation for the three months ended March 31, 2012 compared to \$2.5 million expensed and \$1.9 million capitalized for the comparable period in 2011. We refer you to Note 16 in the unaudited condensed consolidated financial statements included in this Form 10-Q for additional discussion of our equity based compensation plans.

New Accounting Standards

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

In July 2011, the FASB issued Accounting Standards Update No. 2011-05, *Presentation of Comprehensive Income* (“Update 2011-05”), which amends Topic 200, *Comprehensive Income*. Update 2011-05 eliminates the option to present components of other comprehensive income (“OCI”) in the statement of changes in stockholders’ equity, and requires presentation of total comprehensive income and components of net income in a single statement of comprehensive income, or in two separate, consecutive statements. Update 2011-05 requires presentation of reclassification adjustments for items transferred from OCI to net income on the face of the financial statements where the components of net income and the components of OCI are presented. The amendments do not change current treatment of items in OCI, transfer of items from OCI, or reporting items in OCI net of the related tax impact. Update 2011-05 is effective for fiscal years and interim periods beginning after December 15, 2011. The Company early adopted all disclosure requirements of 2011-05 for the year-end December 31, 2011, except those items which were deferred by Accounting Standards Update No. 2011-12, *Comprehensive Income (Topic 220): Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05*. The implementation of these changes did not have an impact on the Company’s results of operations, financial position or cash flows.

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, funds accessed through debt and equity markets and funds from asset dispositions 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"), which are expected to exceed the net cash generated by our operations. We refer you to Note 9 to the consolidated financial statements included in this Form 10-Q and the section below under "Financing Requirements" for additional discussion of our Credit Facility.

Net cash provided by operating activities increased 12% to \$444.7 million for the three months ended March 31, 2012 compared to \$396.5 million for the same period in 2011, due primarily to an increase in changes in working capital, offset slightly by a decrease in net income resulting from decreased revenues due to lower realized gas prices. During the three months ended March 31, 2012, requirements for our capital investments were funded primarily from our cash generated by operating activities, cash equivalents, and borrowings under our Credit Facility. For the three months ended March 31, 2012, cash generated from our operating activities funded 80% of our cash requirements for capital investments and 75% for the three months ended March 31, 2011.

At March 31, 2012 our capital structure consisted of 29% debt and 71% equity and we had \$206 million in cash and cash equivalents. 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 \$573.1 million for the three months ended March 31, 2012 compared to \$530.5 million for the same period in 2011. Our E&P segment investments were \$533.1 million for the three months ended March 31, 2012 compared to \$468.2 million for the same period in 2011. Our E&P segment capitalized internal costs of \$41.6 million for the three months ended March 31, 2012 compared to \$37.6 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. The increase in internal costs capitalized is due to the addition of personnel and related costs in our exploration and development segment.

Our capital investments for 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. 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 2012 capital investment program is expected to be funded through cash flow from operations, cash equivalents, and borrowings under our Credit Facility. The 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 March 31, 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 did not have an outstanding balance under our revolving credit facility at March 31, 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 March 31, 2012, our capital structure under our Credit Facility was 31% debt and 69% equity, which excluded hedging activities, pension and other postretirement liabilities but included the effect of the full cost ceiling impairment that occurred in 2009. We were in compliance with all of the covenants of our Credit Facility at March 31, 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 will be used for general corporate purposes.

At March 31, 2012, our capital structure consisted of 29% debt and 71% equity (exclusive of cash and cash equivalents) and \$206 million in cash and cash equivalents, compared to 25% debt and 75% equity at December 31, 2011. Equity at March 31, 2012 included an accumulated other comprehensive gain of \$490.7 million related to our hedging activities and a loss for \$15.6 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 March 31, 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 May 1, 2012, we had NYMEX commodity price hedges in place on 199.7 Bcf of our remaining targeted 2012 natural gas production and 185.2 Bcf of our expected 2013 natural gas production. The amount of long-term debt we incur will be 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 March 31, 2012, no liability has been recognized in connection with the promissory notes due to the Company's investments in New Brunswick as of March 31, 2012 and its future investment plans.

Substantially all of our employees are covered by defined pension and postretirement benefit plans. We currently expect to contribute approximately \$16.2 million to our pension plans and \$0.1 million to our postretirement benefit plan in 2012. As of March 31, 2012, we have contributed \$3.0 million to the pension plans and less than \$0.1 million to the postretirement benefit plan. At March 31, 2012, we recognized a liability of \$20.5 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 and claims (including with respect to environmental matters) that arise in the ordinary course of business. Management believes, individually or in aggregate, such litigation and claims will not have a material adverse impact on our results of operations, financial position or cash flows, but these matters are subject to inherent uncertainties and management's view may change in the future, at which time management may reserve amounts that are reasonably estimable. For further information regarding commitments and contingencies, we refer you to Note 10 in the unaudited condensed consolidated financial statements included in this Form 10-Q.

Working Capital

We had positive working capital of \$267.8 million at March 31, 2012 and positive working capital of \$93.4 million at December 31, 2011. Current assets increased by \$250.1 million during the three months ended March 31, 2012 primarily due to a \$190.5 million increase in cash and cash equivalents, which is the result of our increased borrowing, and a \$106.2 million increase in current hedging asset, partially offset by \$42.6 million decrease in accounts receivable. Current liabilities increased by \$75.7 million during the three months ended March 31, 2012 primarily as a result of a \$40.1 million increase in current deferred income taxes, a \$34.2 million increase in advances from partners and a \$8.3 million increase in taxes payable, which were partially offset by a \$6.7 million decrease in interest payable and a \$2.1 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 three months ended, March 31, 2012. See “Commodities Risk” below for discussion of credit risk associated with commodities trading.

Interest Rate Risk

At March 31, 2012, we had \$1.7 billion of total debt with a weighted average interest rate of 5.45%. Our revolving credit facility has a floating interest rate (2.20% at March 31, 2012). At March 31, 2012, we had no borrowings outstanding under our Credit Facility. Interest rate swaps may be used to adjust interest rate exposures when deemed appropriate. We do not have any interest rate swaps in effect currently.

Commodities Risk

We use over-the-counter natural gas and crude oil swap agreements and options to hedge sales of our production and to hedge activity in our Midstream Services segment against the inherent price risks of adverse price fluctuations or locational pricing differences between a published index and the NYMEX futures market. These swaps and options include (1) transactions in which one party will pay a fixed price (or variable price) for a notional quantity in exchange for receiving a variable price (or fixed price) based on a published index (referred to as price swaps), (2) transactions in which parties agree to pay a price based on two different indices (referred to as basis swaps) and (3) the purchase and sale of index-related puts and calls (collars) that provide a “floor” price, below which the counterparty pays funds equal to the amount by which the price of the commodity is below the contracted floor, and a “ceiling” price above which we pay to the counterparty the amount by which the price of the commodity is above the contracted ceiling.

The primary market risks relating to our derivative contracts are the volatility in market prices and basis differentials for natural gas and crude oil. However, the market price risk is offset by the gain or loss recognized upon the related sale or purchase of the natural gas or sale of the oil that is hedged. Credit risk relates to the risk of loss as a result of non-performance by our counterparties. The counterparties are primarily major commercial banks, investment banks and integrated energy companies which management believes present minimal credit risks. The credit quality of each counterparty and the level of financial exposure we have to each counterparty are closely monitored to limit our credit risk exposure. Additionally, we perform both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. We have not incurred any counterparty losses related to non-performance and do not anticipate any losses given the information we have currently. However, given the recent volatility in the financial markets, we cannot be certain that we will not experience such losses in the future.

Exploration and Production

The following table provides information about our financial instruments that are sensitive to changes in commodity prices and that are used to hedge prices for natural gas production. The table presents the notional amount in Bcf, the weighted average contract prices and the fair value by expected maturity dates. At March 31, 2012, the fair value of our financial instruments related to natural gas production was an \$819.6 million asset.

	Volume	Weighted Average Price to be Swapped (\$/MMBtu)	Weighted Average Floor Price (\$/MMBtu)	Weighted Average Ceiling Price (\$/MMBtu)	Weighted Average Basis Differential (\$/MMBtu)	Fair value at March 31, 2012 (\$ in millions)
Natural Gas (Bcf):						
Fixed Price Swaps:						
2012	139.2	\$ 5.02	\$ —	\$ —	\$ —	\$ 346.4
2013	185.2	\$ 5.06	\$ —	\$ —	\$ —	\$ 289.0
Floating Price Swaps:						
2012	4.4	\$ 5.67	\$ —	\$ —	\$ —	\$ (0.3)
Costless-Collars:						
2012	60.5	\$ —	\$ 5.50	\$ 6.67	\$ —	\$ 180.1
Basis Swaps:						
2012	27.5	\$ —	\$ —	\$ —	\$ 0.06	\$ 1.4
2013	30.1	\$ —	\$ —	\$ —	\$ 0.07	\$ 2.1
2014	9.1	\$ —	\$ —	\$ —	\$ (0.03)	\$ 0.9

At March 31, 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 three months ended March 31, 2012, we recorded an unrealized gain of \$1.2 million related to the basis swaps that did not qualify for hedge accounting treatment and an unrealized gain of \$5.2 million related to the change in estimated ineffectiveness of our cash flow hedges. Typically, our hedge ineffectiveness results from changes at the end of a reporting period in the price differentials between the index price of the derivative contract, which is primarily a NYMEX price, and the index price for the point of sale for the cash flow that is being hedged.

At December 31, 2011, our basis swaps did not qualify for hedge accounting treatment. Changes in the fair value of derivatives that do not qualify as cash flow hedges are recorded in natural gas and oil sales. For the year ended December 31, 2011, we recorded an unrealized gain of \$5.2 million related to the basis swaps that did not qualify for hedge accounting treatment and an unrealized loss of \$4.2 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 March 31, 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 March 31, 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 million as well as other remedies, including special damages and punitive damages of four times the amount of actual damages established at trial.

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

consistent with his findings in his June 2, 2011 letter and the disgorgement award. 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 prejudgment 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.

The Company believes that SEPCO has a number of legal grounds for appealing the judgment, all of which will be vigorously pursued. Based on the Company's understanding and judgment of the facts and merits of this case, including appellate defenses, and after considering the advice of counsel, the Company has determined that, although reasonably possible after exhaustion of all appeals, an adverse final outcome to this lawsuit is not probable. As such, the Company has not accrued any amounts with respect to this lawsuit. If the plaintiff and intervenor were to ultimately prevail in the appellate process, the Company currently estimates, based on the 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. The Company has not accrued any amounts with respect to this lawsuit and cannot reasonably estimate the amount of any potential liability based on the Company's understanding and judgment of the facts and merits of this case.

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

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 or our results of operations 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.

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.

- (3.1) Amended and Restated By laws of Southwestern Energy Company effective as of February 23, 2012 (Incorporated by reference to Exhibit 3.1 to Registrants Form 8-K filed on February 27, 2012)
- (4.1) Indenture by and among Southwestern Energy Company, SEECO, Inc., Southwestern Energy Production Company, Southwestern Energy Services Company and the Bank of New York Trust Company, N.A., as trustee, dated as of March 5, 2012 (Incorporated by reference to Exhibit 4.1 to Registrant's Form 8-K filed March 6, 2012)
- (4.2) Form of the Notes (included as an exhibit to the Indenture filed as Exhibit 4.1)
- (4.3) Registration Rights Agreement between Southwestern Energy Company and the Initial Purchasers thereunder, dated as of March 5, 2012 (Incorporated by reference to Exhibit 4.3 to Registrant's Form 8-K filed on March 6, 2012)
- (10.1) Retirement Letter Agreement dated February 24, 2012 between Southwestern Energy Company and Gene A. Hammons, including Consulting Agreement of even date (Incorporated by reference to Exhibit 10.1 to Registrant's form 8-K Filed on February 27, 2012)
- (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: May 3, 2012

/s/ GREG D. KERLEY

Greg D. Kerley
Executive Vice President
and Chief Financial Officer