Swift Christopher
Form 4
March 01, 2012

FORM 4

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

OMB APPROVAL

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STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

(Print or Type Responses)

1. Name and Address of Reporting Person *
Swift Christopher

(Last) (First) (Middle)

ONE HARTFORD PLAZA

(Street)

HARTFORD, CT 06155

(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
HARTFORD FINANCIAL SERVICES GROUP INC/DE [HIG]

3. Date of Earliest Transaction (Month/Day/Year)
02/28/2012

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

_____ Director _____ 10% Owner
__X__ Officer (give title below) _____ Other (specify below)
Executive VP and CFO

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			
Restricted Stock Units								58,033.314	D	

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

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SEC 1474 (9-02)

Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security (Instr. 3)	2. Conversion or Exercise Price of Derivative Security	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any (Month/Day/Year)	4. Transaction Code (Instr. 8)		5. Number of Derivative Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)		6. Date Exercisable and Expiration Date (Month/Day/Year)		7. Title and Amount of Underlying Securities (Instr. 3 and 4)	
				Code	V	(A)	(D)	Date Exercisable	Expiration Date	Title	Amount or Number of Shares
Stock Options	$ 28.91							(1)	03/01/2021	Common Stock	92,9
Stock Options	$ 20.63	02/28/2012		A		148,448		(2)	02/28/2022	Common Stock	148,4
Restricted Units	(3)							(3)	05/03/2013	Common Stock	36,867
Deferred Units	(4)							(4)	05/03/2013	Common Stock	2,936.
Deferred Units	(5)							(5)	08/06/2013	Common Stock	3,772.

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
Swift Christopher ONE HARTFORD PLAZA HARTFORD, CT 06155			Executive VP and CFO	

Signatures

/s/ Anthony J. Salerno, by Power of Attorney for Christopher J. Swift dated January 31, 2012.	03/01/2012
**Signature of Reporting Person	Date

Explanation of Responses:

* If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

(1) One-third of the options became exercisable on March 1, 2012, an additional one-third of the options will become exercisable on March 1, 2013 and the remaining one-third of the options will become exercisable on March 1, 2014, the third anniversary of the grant date.

(2) One-third of the options will become exercisable on February 28, 2013, an additional one-third of the options will become exercisable on February 28, 2014 and the remaining one-third of the options will become exercisable on February 28, 2015, the third anniversary of the grant date.

(3) The restricted unit award will be settled in cash on the third anniversary of the grant date (May 3, 2010) based on the Company's closing stock price on the New York Stock Exchange on the expiration date.

(4) One-third of the deferred unit award will be settled in cash as soon as practicable, and in any event within 90 days, after the first, second and third anniversaries of the grant date (May 3, 2010) based on the Company's closing stock price on the New York Stock Exchange on the applicable anniversary date. Deferred units are fully vested when credited.

(5) One-third of the deferred unit award will be settled in cash as soon as practicable, and in any event within 90 days, after the first, second and third anniversaries of the grant date (August 6, 2010) based on the Company's closing stock price on the New York Stock Exchange on the applicable anniversary date. Deferred units are fully vested when credited.

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
Potential persons who are to respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB number. -SIZE: 9pt; MARGIN: 0px; LINE-HEIGHT: 11pt" align=right> 496,818

(1,812,460)

Long-term debt

1,215,400

1,215,400

Deferred income taxes

(97,937)

1,221,864

200,043

	1,323,970
Other liabilities	
	45,888
	80,409
	2,654
	128,951
Total liabilities	
	1,303,678
	3,178,843
	765,609
	(1,812,460)
	3,435,670
Commitments and contingencies	

Total equity	3,306,431	2,324,561	264,588	(2,589,149)	3,306,431
Total liabilities and equity	$ 4,610,109	$ 5,503,404	$ 1,030,197	$ (4,401,609)	$ 6,742,101

Explanation of Responses:

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CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
December 31, 2010:					
ASSETS					
Cash and cash equivalents	$ 8,381	$ 7,631	$ 43	$	$ 16,055
Accounts receivable	382	331,154	20,037		351,573
Inventories		34,263	835		35,098
Other current assets	5,015	171,060	2,092		178,167
Total current assets	13,778	544,108	23,007		580,893
Intercompany receivables	1,820,857	131	18,724	(1,839,712)	
Investments		11,103	(11,102)	(1)	
Property and equipment	124,823	7,871,279	984,783		8,980,885
Less: Accumulated depreciation, depletion and amortization	52,256	3,526,010	104,422		3,682,688
	72,567	4,345,269	880,361		5,298,197
Investments in subsidiaries (equity method)	2,253,871			(2,253,871)	
Other assets	18,918	92,747	26,708		138,373
Total assets	$ 4,179,991	$ 4,993,358	$ 937,698	$ (4,093,584)	$ 6,017,463
LIABILITIES AND EQUITY					
	$ 175,476	$ 336,411	$ 33,208	$	$ 545,095

Accounts and notes payable					
Other current liabilities	3,288	142,839	2,761		148,888
Total current liabilities	178,764	479,250	35,969		693,983
Intercompany payable		1,317,696	522,017	(1,839,713)	
Long-term debt	1,093,000				1,093,000
Deferred income taxes	(98,206)	1,066,166	162,332		1,130,292
Other liabilities	41,557	89,986	3,769		135,312
Total liabilities	1,215,115	2,953,098	724,087	(1,839,713)	3,052,587
Commitments and contingencies					
Total equity	2,964,876	2,040,260	213,611	(2,253,871)	2,964,876
Total liabilities and equity	$ 4,179,991	$ 4,993,358	$ 937,698	$ (4,093,584)	$ 6,017,463

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

(Unaudited)

	Parent	Guarantors	Non-Guarantors (in thousands)	Eliminations	Consolidated
Six months ended June 30, 2011:					
Net cash provided by (used in) operating activities	$ (29,781)	$ 763,933	$ 122,778	$	$ 856,930
Investing activities:					
Capital investments	(35,347)	(889,700)	(99,611)		(1,024,658)
Proceeds from sale of property and equipment		120,892	241		121,133
Transfers to restricted cash	(85,002)				(85,002)
Other	7,244	(11,339)	7,974		3,879
Net cash used in investing activities	(113,105)	(780,147)	(91,396)		(984,648)

Financing activities:					
Intercompany activities	22,870	8,583	(31,453)		
Payments on current portion of long-term debt	(600)				(600)
Payments on revolving long-term debt	(1,717,600)				(1,717,600)
Borrowings under revolving long-term debt	1,840,600				1,840,600
Other items	2,415				2,415
Net cash provided by (used in) financing activities	147,685	8,583	(31,453)		124,815
Effect of exchange rate changes on cash			127		127
Increase (decrease) in cash and cash equivalents	4,799	(7,631)	56		(2,776)
Cash and cash equivalents at beginning of year	8,381	7,631	43		16,055
Cash and cash equivalents at end of period	$ 13,180	$	$ 99	$	$ 13,279
<u>Six months ended June 30, 2010:</u>					
Net cash provided by (used in) operating activities	$ (29,605)	$ 701,961	$ 136,697	$	$ 809,053
Investing activities:					
Capital investments	(23,175)	(814,494)	(147,641)		(985,310)
Proceeds from sale of property and equipment		347,150	1,224		348,374
Transfers to restricted cash	(355,773)				(355,773)
Other	6,364	(13,016)	4,207		(2,445)
Net cash used in investing activities	(372,584)	(480,360)	(142,210)		(995,154)
Financing activities:					

Intercompany activities	221,780	(227,355)	5,575		
Payments on current portion of long-term debt	(600)				(600)
Payments on revolving long-term debt	(1,297,000)				(1,297,000)
Borrowings under revolving long-term debt	1,478,100				1,478,100
Other items	6,365				6,365
Net cash provided by (used in) financing activities	408,645	(227,355)	5,575		186,865
Increase (decrease) in cash and cash equivalents	6,456	(5,754)	62		764
Cash and cash equivalents at beginning of year	7,378	5,776	30		13,184
Cash and cash equivalents at end of period	$ 13,834	$ 22	$ 92	$	$ 13,948

ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

The following updates information as to Southwestern Energy Company s financial condition provided in our 2010 Annual Report on Form 10-K and analyzes the changes in the results of operations between the three- and six-month periods ended June 30, 2011 and 2010. For definitions of commonly used natural gas and oil terms used in this Form 10-Q, please refer to the Glossary of Certain Industry Terms provided in our 2010 Annual Report on Form 10-K.

The following discussion contains forward-looking statements that involve risks and uncertainties. Our actual results could differ materially from those anticipated in forward-looking statements for many reasons, including the risks described in the Cautionary Statement About Forward-Looking Statements in the forepart of this Form 10-Q, in Item 1A, Risk Factors in Part I and elsewhere in our 2010 Annual Report on Form 10-K, and Item 1A, Risk Factors in Part II in this Form 10-Q and any other Form 10-Q filed during the fiscal year. You should read the following discussion with our unaudited condensed consolidated financial statements and the related notes included in this Form 10-Q.

OVERVIEW

Background

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

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

We are focused on providing long-term growth in the net asset value of our business, which we achieve in our E&P business through the drillbit. We derive the vast majority of our operating income and cash flow from the natural gas production of our E&P business and expect this to continue in the future. We expect that growth in our operating income and revenues will primarily depend on natural gas prices and our ability to increase our natural gas production. We expect our natural gas production volumes will continue to increase due to our ongoing development of the Fayetteville Shale play in Arkansas and the Marcellus Shale play in Pennsylvania. The price we expect to receive for our natural gas is a critical factor in the capital investments we make in order to develop our properties and increase our production. In recent years, there has been a significant decline in natural gas prices as evidenced by New York Mercantile Exchange (NYMEX) natural gas prices ranging from a high of $13.58 per Mcf in 2008 to a low of $2.51 per Mcf in 2009. Natural gas prices fluctuate due to a variety of factors we cannot control or predict. These factors, which include increased supplies of natural gas due to greater exploration and development activities, weather conditions, political and economic events, and competition from other energy sources, impact supply and demand for natural gas, which in turn determines the sale prices for our production. In addition to the factors identified above, the prices we realize for our production are affected by our hedging activities as well as locational differences in market prices.

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

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

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

increased slightly to $4.30 per Mcf for the three months ended June 30, 2011 compared to $4.27 per Mcf for the same period in 2010.

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

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

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

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

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

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

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

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

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

Recent Development

Sale of Certain East Texas Properties

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

RESULTS OF OPERATIONS

The following discussion of our results of operations for our segments is presented before intersegment eliminations. We evaluate our segments as if they were stand alone operations and accordingly discuss their results prior to any intersegment eliminations. Interest expense, income tax expense and stock-based compensation are discussed on a consolidated basis.

Exploration and Production

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

Taxes, other than income taxes	$	0.11	$	0.09	$	0.11	$	0.11
Full cost pool amortization	$	1.28	$	1.33	$	1.30	$	1.37

Revenues

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

Production

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

Commodity Prices

The average price realized for our natural gas production, including the effects of hedges, increased slightly to $4.30 per Mcf for the three months ended June 30, 2011, as compared to the same period in 2010. The slight increase was the result of a $0.15 Mcf increase in average gas prices, excluding hedges, mostly offset by the decreased effect of our price hedging activities. The average price realized for our natural gas production, including the effects of hedges, decreased 13% to $4.21 per Mcf for the six months ended June 30, 2011, as compared to the same period in 2010. The decrease in the average price realized for six months ended June 30, 2011, as compared to the same period in 2010, primarily reflects the decrease in average gas prices, excluding hedges, in addition to the decreased effect of our price hedging activities. We periodically enter into various hedging and other financial arrangements with respect to a portion of our projected natural gas and crude oil production in order to ensure certain desired levels of cash flow and to minimize the impact of price fluctuations, including fluctuations in locational basis differentials (we refer you to Item 3 and Note 7 to the unaudited condensed consolidated financial statements included in this Form 10-Q for additional discussion).

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

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

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

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

Operating Income

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

Operating Costs and Expenses

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

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

Taxes other than income taxes per Mcfe increased to $0.11 for the three months ended June 30, 2011 compared to $0.09 for the same period in 2010 and remained flat at $0.11 for the six months ended June 30, 2011 and 2010. Taxes other than income taxes per Mcfe vary from period to period due to changes in severance and ad valorem taxes that result from the mix of our production volumes and fluctuations in commodity prices.

Our full cost pool amortization rate averaged $1.28 per Mcfe for the three months ended June 30, 2011 compared to $1.33 per Mcfe for the same period in 2010. The decline in the average amortization rate for the three months ended June 30, 2011 compared to the same period of 2010 was primarily the result of lower acquisition and development costs, combined with the sale of certain East Texas oil and natural gas leases and wells in the second quarter of 2010, as the proceeds from the sale were appropriately credited to the full cost pool. For the first six months of 2011, our full cost pool amortization rate averaged $1.30 per Mcfe compared to $1.37 per Mcfe for the same period in 2010. The decline in the average amortization rate for the six months ended June 30, 2011 compared to the same period of 2010 was primarily due to the sale of certain East Texas oil and natural gas leases and wells in the second quarter of 2010, as the proceeds from the sale were appropriately credited to the full cost pool, combined with lower acquisition and development costs. The amortization rate is impacted by the timing and amount of reserve additions and the costs associated with those additions, revisions of previous reserve estimates due to both price and well performance, write-downs that result from full cost ceiling tests, proceeds from the sale of properties that reduce the full cost pool and the levels of costs subject to amortization. We cannot predict our future full cost pool amortization rate with accuracy due

to the variability of each of the factors discussed above, as well as other factors, including but not limited to the uncertainty of the amount of future reserves attributed to our Fayetteville Shale play.

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

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

Midstream Services

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

Revenues

Revenues from our marketing activities were up 36% to $661.6 million for the three months ended June 30, 2011 and were up 19% to $1,248.2 million for the six months ended June 30, 2011 compared to the respective periods of 2010. For the three months ended June 30, 2011, the volumes marketed increased 30% and the price received for volumes marketed increased 5% compared to the same period in 2010. For the six months ended June 30, 2011, the volumes marketed increased 31% and the price received for volumes marketed decreased 9% compared to the same period in 2010. Increases and decreases in marketing revenues due to changes in commodity prices are largely offset by corresponding changes in gas purchase expenses. Of the total volumes marketed, production from our E&P operated wells accounted for 92% and 96% of the marketed volumes for the three months ended June 30, 2011 and 2010, respectively. For the six months ended June 30, 2011 and 2010, production from our E&P operated wells accounted for 93% and 97% of the marketed volumes, respectively.

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

Operating Income

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

and an increase of $4.3 million in the margin generated from our gas marketing activities, which was partially offset by a $23.0 million increase in operating costs and expenses, exclusive of gas purchase costs, associated with the increase in gas volumes gathered.

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

Interest Expense

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

Income Taxes

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

Stock-Based Compensation Expense

We expensed $2.2 million and capitalized $1.9 million for stock-based compensation during the three-month period ended June 30, 2011 compared to $2.1 million expensed and $1.7 million capitalized for the comparable period in 2010. We expensed $4.7 million and capitalized $3.8 million for stock-based compensation costs recognized during the six-month period ended June 30, 2011 compared to $4.4 million expensed and $3.4 million capitalized for the comparable period in 2010. We refer you to Note 13 in the unaudited condensed consolidated financial statements included in this Form 10-Q for additional discussion of our equity based compensation plans.

New Accounting Standards

On January 1, 2011, we implemented certain provisions of Accounting Standards Update No. 2010-06, Fair Value Measurements and Disclosures (Topic 820) Improving Disclosures about Fair Value Measurements (Update 2010-06). Update 2010-06 requires entities to provide a reconciliation of purchases, sales, issuance and settlements of anything valued with a Level 3 method, which is used to price the hardest to value instruments. The implementation did not have an impact on our results of operations, financial position or cash flows.

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

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

LIQUIDITY AND CAPITAL RESOURCES

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

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

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

At June 30, 2011 our capital structure consisted of 27% debt and 73% equity. We believe that our operating cash flow and available funds under our Credit Facility will be adequate to meet our capital and operating requirements for 2011. The credit status of the financial institutions participating in our Credit Facility could adversely impact our ability to borrow funds under the Credit Facility. While we believe all of the lenders under the facility have the ability to provide funds, we cannot predict whether each will be able to meet its obligation.

Our cash flow from operating activities is highly dependent upon the market prices that we receive for our natural gas and oil production. Natural gas and oil prices are subject to wide fluctuations and are driven by market supply and demand factors which are impacted by the overall state of the economy. The price received for our production is also influenced by our commodity hedging activities, as more fully discussed in Item 3, Quantitative and Qualitative Disclosures about Market Risks and Note 7 in the unaudited condensed consolidated financial statements included in this Form 10-Q. Our commodity hedging activities are subject to the credit risk of our counterparties being financially unable to complete the transaction. We actively monitor the credit status of our counterparties, performing both quantitative and qualitative assessments based on their credit ratings and credit default swap rates where applicable, and to date have not had any credit defaults associated with our transactions. However, any future failures by one or more counterparties could negatively impact our cash flow from operating activities.

Additionally, our short-term cash flows are dependent on the timely collection of receivables from our customers and partners. We actively manage this risk through credit management activities and through the date of this filing have not experienced any significant write-offs for non-collectable amounts. However, any sustained inaccessibility of credit by our customers and partners could adversely impact our cash flows.

Due to the above factors, we are unable to forecast with certainty our future level of cash flow from operations. Accordingly, we will adjust our discretionary uses of cash dependent upon available cash flow.

Capital Investments

Our capital investments were $1.1 billion for the six months ended June 30, 2011 compared to $1.0 billion for the same period in 2010. Our E&P segment investments were $944.3 million for the six months ended June 30, 2011 compared to $852.7 million for the same period in 2010. Our E&P segment capitalized internal costs of $73.6 million for the six months ended June 30, 2011 compared to $67.0 million for the comparable period in 2010. These internal costs were directly related to acquisition, exploration and development activities and are included as part of the cost of natural gas and oil properties. The increase in internal costs capitalized is due to the addition of personnel and related costs in our exploration and development segment.

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

Financing Requirements

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

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

The interest rate on our Credit Facility is calculated based upon our public debt rating and is currently 200 basis points over LIBOR. Our publicly traded notes are rated BBB- by Standard and Poor s and we have a Corporate Family Rating of Ba1 by Moody s. Any downgrades in our public debt ratings could increase our cost of funds under the Credit Facility.

Our Credit Facility contains covenants which impose certain restrictions on us. Under the Credit Facility, we must keep our total debt at or below 60% of our total capital, and must maintain a ratio of EBITDA to interest expense of 3.5 or above. Our Credit Facility s financial covenants with respect to capitalization percentages exclude hedging activities, pension and other postretirement liabilities as well as the effects of non-cash entries that result from any full cost ceiling impairments occurring after the date of the agreement. At June 30, 2011, our capital structure under our

Credit Facility was 28% debt and 72% equity, which excluded hedging activities, pension and other postretirement liabilities but included the effect of the full cost ceiling impairment that occurred in 2009. We were in compliance with all of the covenants of our Credit Facility at June 30, 2011. Although we do not anticipate any violations of our financial covenants, our ability to comply with those covenants is dependent upon the success of our exploration and development program and upon factors beyond our control, such as the market prices for natural gas and oil. If we are unable to borrow under our Credit Facility, we may have to decrease our capital investment plans.

Our capital structure consisted of 27% debt and 73% equity at June 30, 2011 and December 31, 2010. Equity at June 30, 2011 included an accumulated other comprehensive gain of $120.1 million related to our hedging activities and a loss for $12.1 million related to our pension and other postretirement liabilities. The amount recorded in equity for our hedging activities is based on current market values for our hedges at June 30, 2011 and does not necessarily reflect the value that we will receive or pay when the hedges are ultimately settled, nor does it take into account revenues to be received associated with the physical delivery of sales volumes hedged.

Our hedges allow us to ensure a certain level of cash flow to fund our operations. At July 26, 2011 we had NYMEX commodity price hedges in place on 159.9 Bcf of our remaining targeted 2011 natural gas production, 265.7 Bcf of our

expected 2012 natural gas production and 185.2 Bcf of our expected 2013 natural gas production. The amount of long-term debt we incur will be dependent upon commodity prices and our capital investment plans.

Contractual Obligations and Contingent Liabilities and Commitments

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

We have various contractual obligations in the normal course of our operations and financing activities. Other than the increase in our firm transportation commitments, there have been no material changes to our contractual obligations from those disclosed in our 2010 Annual Report on Form 10-K.

Contingent Liabilities and Commitments

In the first quarter of 2010, we were awarded exclusive licenses by the Province of New Brunswick in Canada to conduct an exploration program covering approximately 2.5 million acres in the province. The licenses require us to make certain capital investments in New Brunswick of approximately CAD $47 million in the aggregate over a three year period. In order to obtain the licenses, we provided promissory notes payable on demand to the Minister of Finance of the Province of New Brunswick with an aggregate principal amount of CAD $44.5 million. The promissory notes secure our capital expenditure obligations under the licenses and are returnable to us to the extent we perform such obligations. If we fail to fully perform, the Minister of Finance may retain a portion of the applicable promissory notes in an amount equal to any deficiency. We commenced our Canada exploration program in 2010 and, as of June 30, 2011, no liability has been recognized in connection with the promissory notes.

Substantially all of our employees are covered by defined benefit and postretirement benefit plans. We currently expect to contribute approximately $12.5 million to our pension plans and less than $0.1 million to our postretirement benefit plan in 2011. As of June 30, 2011, we have contributed $5.9 million to our pension plans and less than $0.1 million to our postretirement benefit plan during the year. At June 30, 2011, we recognized a liability of $15.1 million as a result of the underfunded status of our pension and other postretirement benefit plans compared to a liability of $15.9 million at December 31, 2010.

We are subject to litigation and claims (including with respect to environmental matters) that arise in the ordinary course of business. Management believes, individually or in aggregate, such litigation and claims will not have a material adverse impact on our results of operations, financial position or cash flows, but these matters are subject to inherent uncertainties and management s view may change in the future, at which time management may reserve amounts that are reasonably estimable. For further information regarding commitments and contingencies, we refer you to Note 10 in the unaudited condensed consolidated financial statements included in this Form 10-Q.

Working Capital

We had negative working capital of $81.2 million at June 30, 2011 and negative working capital of $113.1 million at December 31, 2010. Current assets increased by $105.2 million at June 30, 2011 compared to December 31, 2010, primarily due to an $85.0 million increase in restricted cash as a result of a deposit related to the sale of certain oil and gas leases, wells and gathering equipment held by us in East Texas. The sale occurred in the second quarter of 2011

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and we deposited $85.0 million of the proceeds from the sale with a qualified intermediary to facilitate potential like-kind exchange transactions pursuant to Section 1031 of the Internal Revenue Code. Current liabilities increased by $73.4 million during the six months ended June 30, 2011 primarily as a result of a $62.3 million increase in accounts payable and a $19.5 million increase in current deferred income taxes related to our hedging activities. We maintain access to funds that may be needed to meet capital requirements through our Credit Facility described in Financing Requirements above.

Natural Gas in Underground Storage

We record our natural gas stored in inventory that is owned by the E&P segment at the lower of weighted average cost or market. The natural gas in inventory for the E&P segment is used primarily to supplement production in meeting the segment s contractual commitments, especially during periods of colder weather. In determining the lower of cost or market for storage gas, we utilize the natural gas futures market in assessing the price we expect to be able to realize for our natural gas in inventory. A significant decline in the future market price of natural gas could result in write-downs of our natural gas in underground storage carrying cost.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risks relating to our operations result primarily from the volatility in commodity prices, basis differentials and interest rates, as well as credit risk concentrations. We use natural gas and crude oil swap agreements and options and interest rate swaps to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas and oil and in interest rates. Our Board of Directors has approved risk management policies and procedures to utilize financial products for the reduction of defined commodity price risk. Utilization of financial products for the reduction of interest rate risks is subject to the approval of our Board of Directors. These policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings.

Credit Risk

Our financial instruments that are exposed to concentrations of credit risk consist primarily of trade receivables and derivative contracts associated with commodities trading. Concentrations of credit risk with respect to receivables are limited due to the large number of our customers and their dispersion across geographic areas. See Commodities Risk below for discussion of credit risk associated with commodities trading.

Interest Rate Risk

At June 30, 2011, we had $1.2 billion of total debt with a weighted average interest rate of 5.10%. Our revolving credit facility has a floating interest rate (2.165% at June 30, 2011). At June 30, 2011, we had $544.2 million of borrowings outstanding under our Credit Facility. Interest rate swaps may be used to adjust interest rate exposures when deemed appropriate. We do not have any interest rate swaps in effect currently.

Commodities Risk

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

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

Exploration and Production

The following table provides information about our financial instruments that are sensitive to changes in commodity prices and that are used to hedge prices for natural gas production. The table presents the notional amount in Bcf, the weighted average contract prices and the fair value by expected maturity dates. At June 30, 2011, the fair value of our financial instruments related to natural gas production was a $199.2 million asset.

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

(1)

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

(2)

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

At June 30, 2011, our basis swaps did not qualify for hedge accounting treatment. Changes in the fair value of derivatives that do not qualify as cash flow hedges are recorded in gas and oil sales. For the six months ended June 30, 2011, we recorded an unrealized gain of $1.8 million related to the basis swaps that did not qualify for hedge accounting treatment and an unrealized gain of $2.1 million related to the change in estimated ineffectiveness of our cash flow hedges. Typically, our hedge ineffectiveness results from changes at the end of a reporting period in the price differentials between the index price of the derivative contract, which is primarily a NYMEX price, and the index price for the point of sale for the cash flow that is being hedged.

At December 31, 2010, we had outstanding natural gas price swaps on total notional volumes of 66.8 Bcf in 2011, 68.1 Bcf in 2012 and 36.5 in 2013 for which we will receive fixed prices ranging from $5.00 to $7.03 per MMBtu. At December 31, 2010, we had collars in place on notional volumes of 62.1 Bcf in 2011 at an average floor and ceiling price of $5.09 and $6.50 per MMBtu, respectively, and collars on notional volumes of 80.5 Bcf in 2012 at an average floor and ceiling price of $5.50 and $6.67 per MMBtu, respectively.

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

Midstream Services

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

ITEM 4. CONTROLS AND PROCEDURES.

We have performed an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures, as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the Exchange Act). Our disclosure controls and procedures are the controls and other procedures that we have designed to ensure that we record, process, accumulate and communicate information to our management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosures and submission within the time periods specified in the SEC s rules and forms. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those determined to be effective can provide only a level of reasonable assurance with respect to financial statement preparation and presentation. Based on the evaluation, our management, including our Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures were effective as of June 30, 2011. There were no changes in our internal control over financial reporting during the three months ended June 30, 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS.

The Company is subject to laws and regulations relating to the protection of the environment. Our policy is to accrue environmental and cleanup related costs of a non-capital nature when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on our financial position, results of operations, and cash flows.

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

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

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

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

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

ITEM 1A. RISK FACTORS.

There were no additions or material changes to the Company s risk factors as disclosed in Item 1A of Part I in the Company s 2010 Annual Report on Form 10-K.

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

Not applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES.

Not applicable.

ITEM 5. OTHER INFORMATION.

Not applicable.

ITEM 6. EXHIBITS.

(31.1)

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

(31.2)

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

(32.1)

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

(101.INS)

Interactive Data File Instance Document

(101.SCH)

Interactive Data File Schema Document

(101.CAL)

Interactive Data File Calculation Linkbase Document

(101.LAB)

Interactive Data File Label Linkbase Document

(101.PRE)

Interactive Data File Presentation Linkbase Document

(101.DEF)

Interactive Data File Definition Linkbase Document

Signatures

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

SOUTHWESTERN ENERGY COMPANY
Registrant

Dated: July 28, 2011

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

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