Arkansas Department of Environmental Quality
Permits Branch, Water Division
5301 Northshore Drive
North Little Rock, AR 72118
(501) 682-0623

29363 KB

NOTICE OF INTENT
PIPELINE HYDROSTATIC TESTING DISCHARGE
NPDES GENERAL PERMIT ARG6700000

APPLICANT INFORMATION	PROJECT INFORMATION
1. Legal Name of Applicant (Operator): DeSoto Gathering Company, LLC	1. Name of the Project: Scotland 2 Discharge south Phase 1
2. Applicant Legal Address: PO Box 789	2. Project Physical Location: 12924 HWY 95 West
3. Applicant City: Conway	3. Project City: Scotland
4. State: AR Zip: 72033	4. State: AR Zip: 72141
5. Applicant Telephone Number: 501-548-6775	6. Project Contact Person and Telephone:
6. Applicant Type (check one): (Note Certification) ☐ State ☐ Federal ☐ Partnership ☐ Sole Proprietorship ☒ Corporation* *State of Incorporation:	Contact Person Name: Amanda Barnett Contact Person Title: Erosion Control Technician Contact Person Telephone Number: 501-548-1468
7. Permit and DMR send to:	10. Project Latitude: N35° 29' 37.180"
ATTN: Stacy Johnson	Longitude: W92° 37' 11.162"
Address: PO Box 789	12. Additional Project Location Information:
City: Conway	Section: 19 Township: 10N Range: 15W
State: AR Zip: 72033	Project County: Van Buren
8. Cognizant Official: Chuck Smith	13. Facility/Project NAICS Codes: 213112
Cognizant Title: Construction Manager	Type of Business: Gas, Compressing Natural
Cognizant Telephone: 501-269-8691	

OUTFALL INFORMATION	
1. Outfall Number: 001	4. Estimated Volume of Discharge: 240,000 gallons
(a) Stream Segment: 11010014	5. Estimated Rate of Discharge: 0.024 MGD
(b) Hydrologic Basin Code: 4E	6. Source of Test Water: Seeco and/or Public Water Supply
(c) Outfall Latitude: N35° 30' 22.916" Longitude: W92° 37' 9.635"	7. Pipeline/Vessel: ☐ USED ☒ VIRGIN ☐ OTHER: N/A
(d) Section: 17 Township: 10N Range: 15W	8. Describe material from which pipeline/vessel was constructed: steel
(e) County: Van Buren	9. Type of fluid normally contained/transported through pipe/vessel: Natural Gas
(f) Start Date: 9/18/2014 End Date: 9/25/2014	10. Corrosion Inhibitors used: Yes ☐ No ☒ If yes, brief description (Including any potentially toxic constituents)
2. Name of Receiving Stream: Un-named Tributary to Scotland Branch	
3. Are any of the Receiving Stream(s) on the latest Clean Water Act section 303(d) list of impaired waters or have an approved TMDL? ☐Yes ☐No ☒N/A If yes, list the Receiving Stream(s): N/A	

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1. Outfall Number: 002	4. Estimated Volume of Discharge: 240,000 gallons
(a) Stream Segment: 11110208	5. Estimated Rate of Discharge: 0.024 MGD
(b) Hydrologic Basin Code: 3F	6. Source of Test Water: Seeco and/or Public Water Supply
(c) Outfall Latitude: N35° 27' 44.824" Longitude: W92° 36' 12.017"	7. Pipeline/Vessel: ☐ USED ☒ VIRGIN ☐ OTHER: N/A
(d) Section: 32 Township: 10N Range: 15W	8. Describe material from which pipeline/vessel was constructed: steel
(e) County: Van Buren	9. Type of fluid normally contained/transported through pipe/vessel: Natural Gas
(f) Start Date: 9/18/2014 End Date: 9/25/2014 2. Name of Receiving Stream: Un-named Tributary ro East Fork Point Remove	10. Corrosion Inhibitors used: Yes ☐ No ☒ If yes, brief description (Including any potentially toxic constituents)
3. Are any of the Receiving Stream(s) on the latest Clean Water Act section 303(d) list of impaired waters or have an approved TMDL? ☐Yes ☐No ☒N/A If yes, list the Receiving Stream(s): N/A	

ADDITIONAL OUTFALLS CAN ADDED USING SEPARATE ATTACHED PAGES.

ADDITIONAL PERMIT INFORMATION

1. Is the permittee capable of meeting the applicable effluent limits and conditions of the general permit? ☒ YES ☐ NO*
   * If the answer is NO, **DO NOT** submit the NOI for permit coverage.
2. Facility has Individual NPDES Permit: ☐ YES (Permit Number _____) ☒ NO
3. **Disclosure Statement**: Arkansas Code Annotated Section 8-1-106 requires that all applicants for the issuance or transfer of any permit, license, certification or operational authority issued by the Arkansas Department of Environmental Quality (ADEQ) file a disclosure statement with their applications. The filing of a disclosure statement is mandatory. No application can be considered complete without one. You must submit a new disclosure statement even if you have one on file with the Department. The form may be obtained from ADEQ web site at: http://www.adeq.state.ar.us/disclosure_stmt.pdf

CERTIFICATION

"I certify that, if this facility is a corporation, it is registered with the Secretary of the State of Arkansas."

"I certify that the cognizant official designated in this Application is qualified to act as a duly authorized representative under the provisions of 40 CFR 122.22(b). If no cognizant official has been designated, I understand that the Department will accept reports signed only by the Applicant. I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations."

Typed or Printed Name: Chuck Smith	Title: Construction Manager
Signature:	Date: 7/21/2014

Arkansas Department of Environmental Quality
Permits Branch, Water Division
5301 Northshore Drive
North Little Rock, AR 72118
(501) 682-0623

ADDITIONAL INFORMATION

1. Additional location description: N/A

2. Additional Comments: N/A

Permittee please check the following:

	Yes	NO		Yes	NO		Yes	NO		Yes	NO
Complete NOI:	☒	☐	Disclosure:	☒	☐	Map:	☒	☐	Fee:	☒	☐

Franchise Tax Account Status

As of: 08/06/2014 09:43:14 AM

This Page is Not Sufficient for Filings with the Secretary of State

DESOTO GATHERING COMPANY, LLC	
Texas Taxpayer Number	32053930684
Mailing Address	1999 BRYAN ST STE 900 DALLAS, TX 75201-3140
Right to Transact Business in Texas	ACTIVE
State of Formation	TX
Effective SOS Registration Date	04/30/2014
Texas SOS File Number	0801981971
Registered Agent Name	C T CORPORATION SYSTEM
Registered Office Street Address	1999 BRYAN ST., STE. 900 DALLAS, TX 75201

ARKANSAS
SECRETARY OF STATE
Mark Martin

Search Incorporations, Cooperatives, Banks and Insurance Companies

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LLC Member information is now confidential per Act 865 of 2007

Use your browser's back button to return to the Search Results

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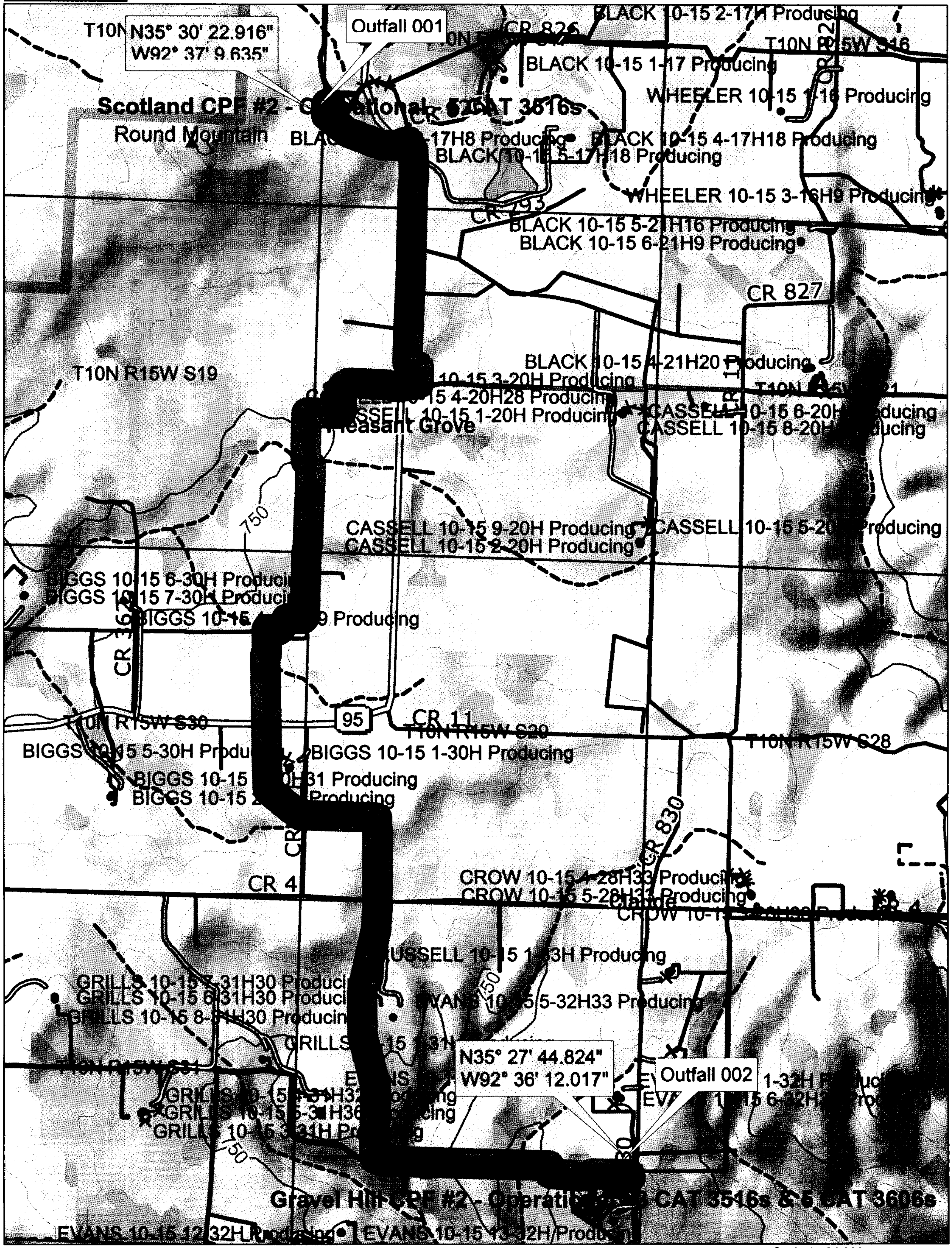
For service of process contact the Secretary of State's office.

Corporation Name	DESOTO GATHERING COMPANY, LLC
Fictitious Names	
Filing #	811054425
Filing Type	Foreign Limited Liability Company
Filed under Act	Foreign LLC; 1003 of 1993
Status	Good Standing
Principal Address	
Reg. Agent	THE CORPORATION COMPANY
Agent Address	124 WEST CAPITOL AVENUE, SUITE 1900 LITTLE ROCK, AR 72201
Date Filed	05/13/2014
Officers	WILLIAM J. WAY , Incorporator/Organizer
Foreign Name	N/A
Foreign Address	2350 N SAM HOUSTON PARKWAY E, SUITE 125 HOUSTON, TX 77032
State of Origin	TX
Purchase a Certificate of Good Standing for this Entity	Pay Franchise Tax for this corporation

DeLorme

XMap® 6



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TN

MN (0.8°E)

Scale 1 : 24,000

1" = 2,000.0 ft

Data Zoom 12-1

swn
Midstream Company™

Conway Office
1000 Southwestern Energy Drive
P.O. Box 789
Conway, Arkansas 72032
www.swn.com

22 January 2014

Ms. Teresa Marks
Director
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118

RE: Delegation of Signature Authority – DeSoto Gathering Company, LLC

Ms. Marks:

Pursuant to Arkansas NPDES General Permit ARG6700000 Hydrostatic Testing Discharge regarding signatory requirements, DeSoto Gathering Company, LLC respectfully submits this delegation of signature authority for all reports and other information required by the Arkansas Department of Environmental Quality Director to Mr. Chuck Smith, Midstream Construction Manager who has responsibility for overall operation of the activities requiring coverage under this General Permit. This delegation is effective until the earlier of its revocation, change in the Midstream Construction Manager role, or a change to the undersigned role. This delegation may not be further delegated.

Sincerely,

John R. Lee
Vice President, Midstream Field Operations

SOUTHWESTERN ENERGY CO

FORM 8-K
(Current report filing)

Filed 07/31/14 for the Period Ending 06/30/14

Address	2350 N. SAM HOUSTON PARKWAY EAST SUITE 125 HOUSTON, TX 77032
Telephone	2816184700
CIK	0000007332
Symbol	SWN
SIC Code	1311 - Crude Petroleum and Natural Gas
Industry	Oil & Gas Operations
Sector	Energy
Fiscal Year	12/31

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

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of report (Date of earliest event reported): July 31, 2014

SOUTHWESTERN ENERGY COMPANY

(Exact name of registrant as specified in its charter)

Delaware
(State or other jurisdiction of incorporation)

1 -08246 **(Commission File Number)**	**71-0205415** **(IRS Employer Identification No.)**
2350 N. Sam Houston Pkwy. E., 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 or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Explanatory Note

The information in this report provided under Item 2.02, including Exhibit 99.1 attached hereto, shall not be deemed to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), or otherwise subject to the liabilities of that Section, and shall not be incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Exchange Act, except as shall be expressly set forth by specific reference in such a filing.

SECTION 2 - Financial Information

Item 2.02 Results of Operations and Financial Condition.

On July 31, 2014, Southwestern Energy Company (the "Company") issued a press release announcing the Company's financial results for the second quarter ended June 30, 2014 (Exhibit 99.1). The press release is being furnished as Exhibit 99.1 .

SECTION 9 - Financial Statements and Exhibits

Item 9.01 Financial Statements and Exhibits.
(d) Exhibits.

99.1	Press release announcing earnings dated July 31, 2014.

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 hereunto duly authorized.

SOUTHWESTERN ENERGY COMPANY

Dated: July 31, 2014	By:	/s/ R. CRAIG OWEN
	Name:	R. Craig Owen
	Title:	Senior Vice President and Chief Financial Officer

EXHIBIT INDEX

Exhibit Number	Description
99.1	Press release announcing earnings dated July 31, 2014.

Corporate Office
2350 N Sam Houston Pkwy E
Suite 125
Houston, Texas 77032
www.swn.com

NEWS RELEASE

SOUTHWESTERN ENERGY ANNOUNCES SECOND QUARTER 2014 FINANCIAL AND OPERATING RESULTS

Houston, Texas – July 31, 2014...Southwestern Energy Company (NYSE: SWN) today announced its financial and operating results for the quarter and six months ended June 30, 2014. Second quarter highlights include:

- Record gas and oil production of 189 Bcfe, up 18% compared to year-ago levels;
- Adjusted net income of $207 million, or $0.59 per diluted share, up 9% compared to year-ago levels when excluding gains and losses on derivative contracts that have not been settled (a non-GAAP measure reconciled below);
- N et cash provided by operating activities before changes in operating assets and liabilities of approximately $579 million, up 18% compared to year-ago levels (a non-GAAP measure reconciled below);
- Strong production growth results in full-year 2014 production guidance increase to 758 to 764 Bcfe, up from previous guidance of 740 to 752 Bcfe; and
- Record well initial production rate of over 14 MMcf per day in the Fayetteville Shale

“Our results this quarter are helping to pave the way for another record year in 2014,” remarked Steve Mueller, President and Chief Executive Officer of Southwestern Energy. “Our production grew 18% and our wells in both the Fayetteville and Marcellus projects continue to perform better than expected. As a result, we have increased our production guidance for 2014 and only slightly revised our 2014 capital estimates, even though we have added a new project in the Niobrara with projected 2014 capital of approximately $280 million. The results from this quarter are continued evidence of the high quality of our current assets and growing portfolio of opportunities that will build even a brighter future.”

Second Quarter of 2014 Financial Results

For the second quarter of 2014, Southwestern reported net income and adjusted net income of $207 million, or $0.59 per diluted share (reconciled below). For the second quarter of 2013, Southwestern reported adjusted net income of $190 million, or $0.54 per diluted share, when excluding a $93 million ($56 million net of taxes) gain on derivative contracts that have not been settled. Including this gain, Southwestern reported net income of $246 million, or $0.70 per diluted share, in the second quarter of 2013 (reconciled below).

Net cash provided by operating activities before changes in operating assets and liabilities (reconciled below) was $579 million for the second quarter of 2014, up 18% compared to $492 million for the same period in 2013.

E&P Segment – Operating income from the company's E&P segment was $275 million for the second quarter of 2014, compared to $253 million for the same period in 2013. The increase was due to higher production volumes, partially offset by lower realized natural gas prices and higher operating costs and expenses due to increased compression and gathering costs.

Gas and oil production totaled 189 Bcfe in the second quarter of 2014, up 18% from 160 Bcfe in the second quarter of 2013, and included 124 Bcf from the Fayetteville Shale, up from 121 Bcf in the second quarter of 2013. Gas production from the Marcellus Shale was 61 Bcf in the second quarter of 2014, nearly double its production of 34 Bcf in the second quarter of 2013. The company has updated its production guidance for the remainder of 2014 due to the continued s trong performance in its Fayetteville and Marcellus Shale operating areas. The revised total gas and oil production guidance for 2014 of 758 to 764 Bcfe is an increase of approximately 16% over the company's 2013 gas and oil production (using midpoints). The company's production guidance for the remainder of 2014 is provided below:

	1st Quarter Actual	2nd Quarter Actual	3rd Quarter Estimate	4th Quarter Estimate	Full-Year 2014 Estimate
Previous Guidance (Bcfe)	177 - 179	183 - 185	187 - 191	193 - 197	740 - 752
New Guidance (Bcfe)	182	189	192 - 194	195 - 199	758 - 764

Including the effect of hedges, Southwestern's average realized gas price in the second quarter of 2014 was $3.77 per Mcf, down from $3.87 per Mcf in the second quarter of 2013. The company's commodity hedging activities decreased its average realized gas price by $0.17 per Mcf during the second quarter of 2014, compared to an increase of $0.29 per Mcf during the same period in 2013. Excluding the effect of hedges, the company's average realized price for the second quarter of 2014 was $4.11 per Mcf for its Fayetteville gas volumes and $3.58 per Mcf for its Marcellus gas volumes, compared to $3.54 per Mcf and $3.66 per Mcf, respectively, in the second quarter of 2013. As of June 30, 2014, the company had approximately 233 Bcf of its remaining 2014 forecasted gas production hedged at an average price of $4.35 per Mcf and approximately 240 Bcf of its 2015 forecasted gas production hedged at an average price of $4.40 per Mcf.

Like most producers, the company typically sells its natural gas at a discount to NYMEX settlement prices. This discount includes a basis differential, third-party transportation charges and fuel charges. Disregarding the impact of hedges, the company's average price received for its gas production during the second quarter of 2014 was approximately $0.73 per Mcf lower than average NYMEX settlement prices, compared to approximately $0.51 per Mcf lower during the second quarter of 2013. As of June 30, 2014, the company had protected approximately 163 Bcf of its remaining 2014 forecasted gas production from the potential of widening basis differentials through hedging activities and sales arrangements at an average basis differential to NYMEX gas prices of approximately ($0.08) per Mcf. While Southwestern expects its discount to NYMEX settlement prices for the full-year of 2014 to range between $0.54 to $0.59 per Mcf.

Lease operating expenses per unit of production for the company's E&P segment were $0.90 per Mcfe in the second quarter of 2014, compared to $0.85 per Mcfe in the second quarter of 2013. The increase was primarily due to an increase in gathering costs in the Marcellus Shale and an increase in compression costs.

General and administrative expenses per unit of production were $0.23 per Mcfe in the second quarter of 2014, compared to $0.24 per Mcfe in the second quarter of 2013, down due to a larger increase in production volumes compared to the increase in personnel costs.

Taxes other than income taxes were $0.11 per Mcfe in both the second quarters of 2014 and 2013. 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 the company's production volumes and fluctuations in commodity prices.

The company's full cost pool amortization rate increased to $1.09 per Mcfe in the second quarter of 2014, compared to $1.05 per Mcfe in the second quarter of 2013. 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. The company cannot predict its future full cost pool amortization rate with accuracy due to the variability of each of the factors discussed above, as well as other factors.

Midstream Services – Operating income for the company's Midstream Services segment, which is comprised of natural gas gathering and marketing activities, was $93 million for the second quarter of 2014, up 27% from $73 million for the same period in 2013. Adjusted EBITDA for the segment was $107 million in the second quarter of 2014, up from $85 million in the same period in 2013 (a non-GAAP measure reconciled below). The growth in operating income and adjusted EBITDA was primarily due to increases in gas volumes gathered and marketing margins.

At June 30, 2014, the company's midstream segment was gathering approximately 2.3 Bcf per day through 1,980 miles of gathering lines in the Fayetteville Shale and approximately 417 MMcf per day from 61 miles of owned gathering lines in the Marcellus Shale. Gathering volumes, revenues and expenses for this segment are expected to grow over the next few years largely as a result of continued development of the company's acreage in the Fayetteville Shale and Marcellus Shale and development activity being undertaken by other operators in those areas.

First Six Months of 2014 Financial Results

For the first six months of 2014, Southwestern reported adjusted net income of $438 million, or $1.24 per diluted share, when excluding a $62 million ($37 million net of taxes) loss on derivative contracts that have not been settled. Including this loss, net income for the first six months of 2014 was $401 million, or $1.14 per diluted share (reconciled below). For the first six months of 2013, the company reported adjusted net income of $336 million, or $0.96 per diluted share, when excluding a $63 million ($37 million net of taxes) gain on derivative contracts that have not been settled. Including this gain, Southwestern reported net income of $373 million, or $1.06 per diluted share (reconciled below).

Net cash provided by operating activities before changes in operating assets and liabilities (reconciled below) was $1.2 billion for the first six months of 2014, up 30% from $918 million for the same period in 2013.

E&P Segment – Operating income from the company's E&P segment was $627 million for the six months ended June 30, 2014, compared to $428 million for the same period in 2013. The increase was primarily due to higher production volumes and higher realized natural gas prices, offset by increased operating costs and expenses due to increased compression and gathering costs.

Gas and oil production was 371 Bcfe in the first six months of 2014, up 20% compared to 308 Bcfe in the first six months of 2013, and included 243 Bcf from the Fayetteville Shale, up from 240 Bcf in the first six months of 2013. Production from the Marcellus Shale was 119 Bcf in the first six months of 2014, more than double its production of 57 Bcf in the first six months of 2013.

Southwestern's average realized gas price was $3.98 per Mcf, including the effect of hedges, in the first six months of 2014 compared to $3.65 per Mcf in the first six months of 2013. The company's hedging activities decreased the average gas price realized during the first six months of 2014 by $0.30 per Mcf, compared to an increase of $0.41 per Mcf during the first six months of 2013. Excluding the effect of hedges, the company's average realized price for the first six months of 2014 was $4.25 per Mcf for its Fayetteville gas volumes and $4.32 per Mcf for its Marcellus gas volumes, compared to $3.19 per Mcf and $3.44 per Mcf, respectively, in the first six months of 2013. Disregarding the impact of hedges, the average price received for the company's gas production during the first six months of 2014 was approximately $0.52 per Mcf lower than average monthly NYMEX settlement prices, compared to approximately $0.47 per Mcf during the first six months of 2013.

Lease operating expenses for the company's E&P segment were $0.91 per Mcfe in the first six months of 2014, compared to $0.83 per Mcfe in the first six months of 2013. The increase was primarily due to an increase in gathering costs in the Marcellus Shale and an increase in compression costs.

General and administrative expenses were $0.24 per Mcfe in the first six months of 2014, compared to $0.23 per Mcfe in the first six months of 2013. The increase was primarily due to higher personnel costs.

Taxes other than income taxes were $0.12 per Mcfe during the first six months of 2014, compared to $0.11 per Mcfe in the first six months of 2013. 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 production volumes and fluctuations in commodity prices.

The company's full cost pool amortization rate increased to $1.10 per Mcfe in the first six months of 2014, compared to $1.07 per Mcfe in the first six months of 2013.

Midstream Services - Operating income for the company's midstream activities was $175 million in the first six months of 2014, up 17% compared to $149 million in the first six months of 2013. Adjusted EBITDA for the segment was $202 million for the first six months of 2014, up from $173 million in the same period in 2013 (a non-GAAP measure reconciled below). The increase in operating income and adjusted EBITDA was primarily due to increases in gas volumes gathered and marketing margins.

Capital Structure and Investments – At June 30, 2014, the company had approximately $1.8 billion in long-term debt, including approximately $172 million borrowed on its revolving credit facility, and its long-term debt-to-total capitalization ratio was 31%.

During the first six months of 2014, Southwestern invested a total of $1.3 billion , up from $1.2 billion in the first six months of 2013, and included approximately $1.2 billion invested in its E&P business, $75 million invested in its Midstream Services segment and $13 million invested for corporate and other purposes. The company has increased its planned total capital investments program for 2014 to approximately $2.4 billion, up 3% from its original capital investment program of approximately $2.3 billion. The following table provides updated annual forecast information for the company's capital program in 2014, compared to its original capital budget.

	Capital Investments	
	Original 2014	Forecast 2014
	(in millions)	
Fayetteville Shale	$ 900	$ 900
Marcellus Shale	760	700
Brown Dense	178	110
Niobrara	–	280
New Ventures	190	115
Ark-La-Tex	7	7
Midstream Services	140	140
Drilling Rigs	95	95
E&P Services and Corporate	55	53
Total Capital Investments	**$ 2,325**	**$ 2,400**

E&P Operations Review

During the first six months of 2014, Southwestern invested a total of approximately $1.2 billion in its E&P business, including $450 million in the Fayetteville Shale, $373 million in the Marcellus Shale, $69 million in the Brown Dense, $191 million in the Niobrara, $2 million in its Ark-La-Tex division, $36 million in New Ventures, $51 million for Drilling Rigs and $4 million in E&P Services .

Marcellus Shale – In the second quarter of 2014, Southwestern placed 23 new wells on production in the Marcellus Shale resulting in net gas production from the Marcellus Shale of 61 Bcf, up approximately 80% from 34 Bcf in the second quarter of 2013. Gross operated production in the Marcellus Shale was approximately 744 MMcf per day at June 30, 2014. With activity to date and the company's planned level of drilling for the remainder of the year, Southwestern estimates that it will drill approximately 73 to 77 operated wells in the Marcellus Shale in 2014, compared to 80 to 85 wells previously forecast.

As of June 30, 2014, Southwestern had 216 operated wells on production and 93 wells in progress. Of the operated wells on production, 215 were horizontal wells of which 102 were located in Bradford County, 16 were located in Lycoming County and 97 were located in Susquehanna County. Of the 93 wells in progress, 34 were either waiting on completion or waiting to be placed to sales, including 8 in Bradford County, 1 in Lycoming County and 25 in Susquehanna County.

Results from the company's drilling activities since the third quarter of 2010 are shown below.

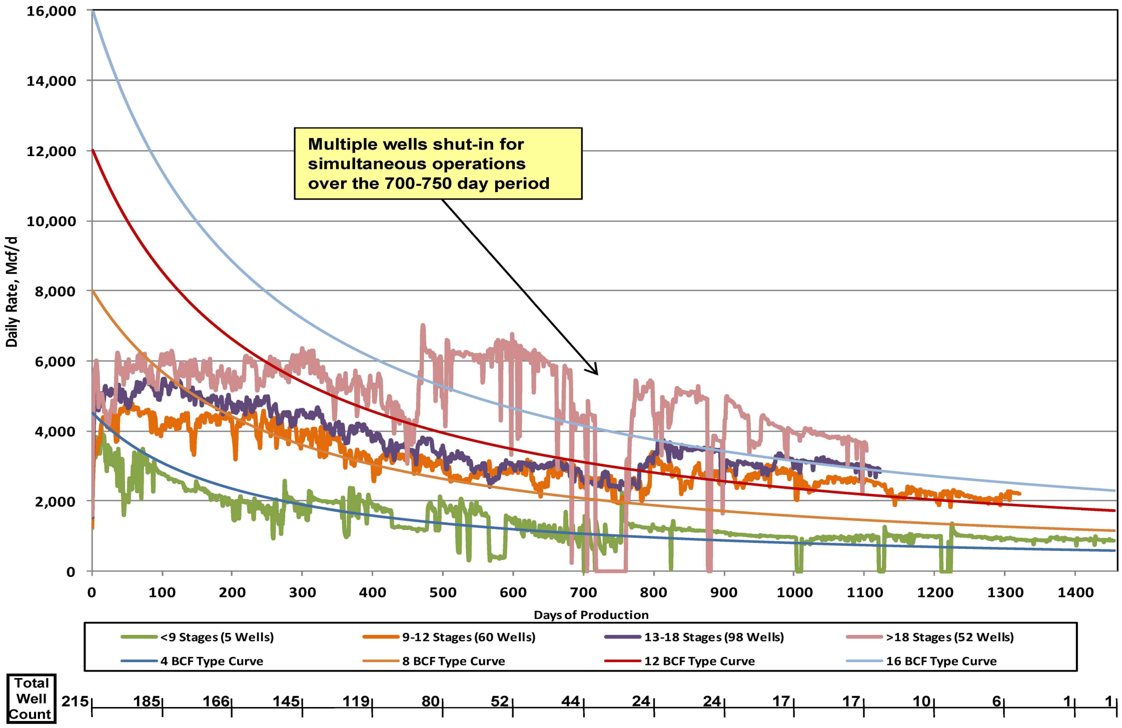
Time Frame	30th-Day Avg Rate (# of wells)	Average Completed Lateral Length*	Average RE-RE (Rig Days)	Average Completed Well Cost ($MM)
3rd Qtr 2010	1,405 (1)	2,927	22.6	$5.8
4th Qtr 2010	5,584 (6)	3,805	19.8	$7.1
1st Qtr 2011	5,052 (3)	3,864	18.1	$6.6
2nd Qtr 2011	6,114 (7)	4,780	13.4	$6.7
4th Qtr 2011	5,284 (5)	4,129	18.8	$6.0
1st Qtr 2012	7,327 (2)	4,009	13.2	$6.0
2nd Qtr 2012	3,859 (17)	3,934	12.9	$6.0
3rd Qtr 2012	4,493 (8)	4,380	13.2	$5.7
4th Qtr 2012	4,606 (22)	3,830	15.9	$7.0
1st Qtr 2013	5,356 (21)	4,712	11.0	$7.0
2nd Qtr 2013	5,530 (37)	4,371	11.6	$6.6
3rd Qtr 2013	4,470 (22)	4,740	11.5	$7.3
4th Qtr 2013	7,589 (20)	6,116	10.2	$7.1
1st Qtr 2014	7,009 (21)	3,859	10.5	$6.2
2nd Qtr 2014	6,979 (14)	5,048	10.3	$6.7

*Average CLAT of wells that have produced for 30 days.

Southwestern continues to test its acreage in Wyoming and Sullivan Counties that was acquired in 2013 and is currently drilling its first horizontal well in Wyoming County, the Dimmig 2H, which is planned to be tested in the fourth quarter. Three vertical wells have also been drilled in Wyoming and Sullivan Counties to help delineate the company's acreage.

Southwestern has also begun testing the Upper Marcellus formation and its first well, the Preston Perkins 7H located in Bradford County, is drilled. The company plans to have four Upper Marcellus wells drilled and completed by year-end.

The graph below provides normalized average daily production data through June 30, 2014, for the company's horizontal wells in the Marcellus Shale. The "pink curve" indicates results for 52 wells with more than 18 fracture stimulation stages, the "purple curve" indicates results for 98 wells with 13 to 18 fracture stimulation stages, the "orange curve" indicates results for 60 wells with 9 to 12 fracture stimulation stages and the "green curve" indicates results for 5 wells with less than 9 fracture stimulation stages. The normalized production curves are intended to provide a qualitative indication of the company's Marcellus Shale wells' performance and should not be used to estimate an individual well's estimated ultimate recovery. The 4, 8,12 and 16 Bcf typecurves are shown solely for reference purposes and are not intended to be projections of the performance of the company's wells.



Notes: Data as of June 30, 2014.

Fayetteville Shale – In the second quarter of 2014, Southwestern placed 147 new wells on production in the Fayetteville Shale resulting in net gas production from the Fayetteville Shale of 124 Bcf in the second quarter of 2014, compared to 121 Bcf in the second quarter of 2013. Gross operated gas production in the Fayetteville Shale was approximately 2,073 MMcf per day at June 30, 2014.

During the second quarter of 2014, the company's horizontal wells in the Fayetteville Shale had an average completed well cost of $2.5 million per well, average horizontal lateral length of 5,390 feet and average time to drill to total depth of 6.7 days from re-entry to re-entry. This compares to an average horizontal lateral length of 5,680 feet and average time to drill to total depth of 6.9 days from re-entry to re-entry for an average completed well cost of $2.5 million per well in the first quarter of 2014. In the second quarter of 2014, the company had 26 operated wells placed on production which had average times to drill to total depth of 5 days or less from re-entry to re-entry. Since inception, the company has drilled 311 wells to total depth in 5 days or less from re-entry to re-entry in the Fayetteville Shale.

During the second quarter, Southwestern placed on production 7 out of the top 10 highest rate wells since it began drilling in the area in 2004, including the Allison Trust 7-16 4-15H11 well located in Conway County which achieved a peak 24-hour production rate of 14,097 Mcf per day. In the second quarter of 2014, the company placed 41 operated wells on production with initial production rates that exceeded 5,000 Mcf per day, and 25 wells that exceeded 6,000 Mcf per day. The company's wells placed on production during the second quarter of 2014 averaged initial production rates of 4,391 Mcf per day. Results from the company's drilling activities since the first quarter of 2007 are shown below.

Time Frame	Wells Placed on Production	Average IP Rate (Mcf/d)	30th-Day Avg Rate (# of wells)	60th-Day Avg Rate (# of wells)	Average Lateral Length
1st Qtr 2007	58	1,261	1,066 (58)	958 (58)	2,104
2nd Qtr 2007	46	1,497	1,254 (46)	1,034 (46)	2,512
3rd Qtr 2007	74	1,769	1,510 (72)	1,334 (72)	2,622
4th Qtr 2007	77	2,027	1,690 (77)	1,481 (77)	3,193
1st Qtr 2008	75	2,343	2,147 (75)	1,943 (74)	3,301
2nd Qtr 2008	83	2,541	2,155 (83)	1,886 (83)	3,562
3rd Qtr 2008	97	2,882	2,560 (97)	2,349 (97)	3,736
4th Qtr 2008 (1)	74	3,350 (1)	2,722 (74)	2,386 (74)	3,850
1st Qtr 2009 (1)	120	2,992 (1)	2,537 (120)	2,293 (120)	3,874
2nd Qtr 2009	111	3,611	2,833 (111)	2,556 (111)	4,123
3rd Qtr 2009	93	3,604	2,624 (93)	2,255 (93)	4,100
4th Qtr 2009	122	3,727	2,674 (122)	2,360 (120)	4,303
1st Qtr 2010 (2)	106	3,197 (2)	2,388 (106)	2,123 (106)	4,348
2nd Qtr 2010	143	3,449	2,554 (143)	2,321 (142)	4,532
3rd Qtr 2010	145	3,281	2,448 (145)	2,202 (144)	4,503
4th Qtr 2010	159	3,472	2,678 (159)	2,294 (159)	4,667
1st Qtr 2011	137	3,231	2,604 (137)	2,238 (137)	4,985
2nd Qtr 2011	149	3,014	2,328 (149)	1,991 (149)	4,839
3rd Qtr 2011	132	3,443	2,666 (132)	2,372 (132)	4,847
4th Qtr 2011	142	3,646	2,606 (142)	2,243 (142)	4,703
1st Qtr 2012	146	3,319	2,421 (146)	2,131 (146)	4,743
2nd Qtr 2012	131	3,500	2,515 (131)	2,225 (131)	4,840
3rd Qtr 2012	105	3,857	2,816 (105)	2,447 (105)	4,974
4th Qtr 2012	111	3,962	2,815 (111)	2,405 (111)	4,784
1st Qtr 2013	102	3,301	2,366 (102)	2,069 (102)	4,942
2nd Qtr 2013	126	3,625	2,233 (126)	1,975 (126)	5,165
3rd Qtr 2013	89	4,597	2,696 (89)	2,391 (89)	5,490
4th Qtr 2013	97	4,901	2,798 (97)	2,553 (97)	5,976
1st Qtr 2014	105	4,272	2,616 (105)	2,205 (105)	5,680
2nd Qtr 2014	147	4,391	2,614 (129)	2,130 (93)	5,390

Note: Results as of June 30, 2014.

(1) The significant increase in the average initial production rate for the fourth quarter of 2008 and the subsequent decrease for the first quarter of 2009 is primarily due to an operational delay of the Boardwalk Pipeline.

(2) In the first quarter of 2010, the company's results were impacted by the shift of all wells to "green completions" and the mix of wells, as a large percentage of wells were placed on production in the shallower northern and far eastern borders of the company's acreage.

Southwestern also continues to test the Upper Fayetteville formation and a total of 45 wells have been drilled to date. The company has drilled 15 Upper Fayetteville wells through the first six months of 2014. While several of the wells drilled in 2014 are choked back and are continuing to clean-up, six of these wells had an average initial production rate over 4.0 million cubic feet of gas per day, with the highest initial production rate being 6.3 million cubic feet of gas per day. The company plans to drill and complete five additional Upper Fayetteville wells later in the year.

Ark-La-Tex – Total net production from the company's East Texas and conventional Arkoma Basin assets was 8.2 Bcfe in the first six months of 2014, compared to 9.5 Bcfe in the first six months of 2013.

New Ventures – On May 1, 2014, the company closed on its previously announced acquisition of approximately 306,000 net acres in northwest Colorado targeting the Niobrara formation for approximately $183 million. Subsequently, in July the company agreed to acquire an additional 74,000 net acres in two separate transactions in the area for approximately $31 million. These agreements are expected to close in the third quarter of 2014. The company is currently completing its first vertical Niobrara well and drilling its second vertical well out of a five well program in 2014. In the Denver–Julesburg Basin in northeast Colorado, the company is currently completing its third vertical well in the Atoka and Marmaton formations.

Explanation and Reconciliation of Non-GAAP Financial Measures

The company reports its financial results in accordance with accounting principles generally accepted in the United States of America ("GAAP"). However, management believes certain non-GAAP performance measures may provide financial statement users with additional meaningful comparisons between current results and the results of its peers and of prior periods.

One such non-GAAP financial measure is net cash provided by operating activities before changes in operating assets and liabilities. Management presents this measure because (i) it is accepted as an indicator of an oil and gas exploration and production company's ability to internally fund exploration and development activities and to service or incur additional debt, (ii) changes in operating assets and liabilities relate to the timing of cash receipts and disbursements which the company may not control and (iii) changes in operating assets and liabilities may not relate to the period in which the operating activities occurred.

Additional non-GAAP financial measures the company may present from time to time are adjusted net income, adjusted diluted earnings per share and its E&P segment operating income, all which exclude certain charges or amounts. Management presents these measures because (i) they are consistent with the manner in which the company's performance is measured relative to the performance of its peers, (ii) these measures are more comparable to earnings estimates provided by securities analysts, and (iii) charges or amounts excluded cannot be reasonably estimated and guidance provided by the company excludes information regarding these types of items. These adjusted amounts are not a measure of financial performance under GAAP.

See the reconciliations below of GAAP financial measures to non-GAAP financial measures for the three and six months ended June 30, 2014 and June 30, 2013, respectively. Non-GAAP financial measures should not be considered in isolation or as a substitute for the company's reported results prepared in accordance with GAAP.

	3 Months Ended June 30, 2014	3 Months Ended June 30, 2013
	(in millions)	
Net income:		
Net income	$ 207	$ 246
Add back (deduct):		
Gain on derivatives excluding derivatives, settled (net of taxes)	–	(56)
Adjusted net income	$ 207	$ 190

	6 Months Ended June 30, 2014	6 Months Ended June 30, 2013
	(in millions)	
Net income:		
Net income	$ 401	$ 373
Add back (deduct):		
Loss (gain) on derivatives excluding derivatives, settled (net of taxes)	37	(37)
Adjusted net income	$ 438	$ 336

	3 Months Ended June 30, 2014	3 Months Ended June 30, 2013
Diluted earnings per share:		
Diluted earnings per share	$ 0.59	$ 0.70
Add back (deduct):		
Gain on derivatives excluding derivatives, settled (net of taxes)	–	(0.16)
Adjusted diluted earnings per share	$ 0.59	$ 0.54

	6 Months Ended June 30, 2014	6 Months Ended June 30, 2013
Diluted earnings per share:		
Diluted earnings per share	$ 1.14	$ 1.06
Add back (deduct):		
Loss (gain) on derivatives excluding derivatives, settled (net of taxes)	0.10	(0.10)
Adjusted diluted earnings per share	$ 1.24	$ 0.96

	3 Months Ended June 30, 2014	3 Months Ended June 30, 2013
	(in millions)	
Cash flow from operating activities:		
Net cash provided by operating activities	$ 585	$ 506
Add back (deduct):		
Change in operating assets and liabilities	(6)	(14)
Net cash provided by operating activities before changes in operating assets and liabilities	$ 579	$ 492

	6 Months Ended June 30,	
	2014	2013
	(in millions)	
Cash flow from operating activities:		
Net cash provided by operating activities	$ 1,194	$ 878
Add back (deduct):		
Change in operating assets and liabilities	2	40
Net cash provided by operating activities before changes in operating assets and liabilities	$ 1,196	$ 918

	3 Months Ended June 30,	
	2014	2013
	(in millions)	
Midstream Services adjusted EBITDA [(1)]:		
Net income	$ 54	$ 44
Add back (deduct):		
Loss (gain) on derivatives excluding derivatives, settled	–	–
Net interest expense	3	3
Provision for income taxes	36	26
Depreciation, depletion and amortization expense	14	12
Adjusted EBITDA	$ 107	$ 85

	6 Months Ended June 30,	
	2014	2013
	(in millions)	
Midstream Services adjusted EBITDA [(1)]:		
Net income	$ 101	$ 89
Add back (deduct):		
Loss (gain) on derivatives excluding derivatives, settled	(1)	–
Net interest expense	7	5
Provision for income taxes	67	55
Depreciation, depletion and amortization expense	28	24
Adjusted EBITDA	$ 202	$ 173

(1) Adjusted EBITDA is defined as net income plus interest, income tax expense, loss (gain) on derivatives excluding derivatives, settled and depreciation, depletion and amortization.

Southwestern management will host a teleconference call on Friday, August 1, 2014 at 10:00 a.m. EDT to discuss its second quarter 2014 results. The toll-free number to call is 877-407-8035 and the international dial-in number is 201-689-8035. The teleconference can also be heard “live” on the Internet at http://www.swn.com .

Southwestern Energy Company is an independent energy company whose wholly-owned subsidiaries are engaged in natural gas and oil exploration and production and natural gas gathering and marketing. Additional information about the company can be found on the internet at http://www.swn.com .

Contacts:	**R. Craig Owen** **Senior Vice President** **and Chief Financial Officer** **(281) 618-2808**	**Brad D. Sylvester, CFA** **Vice President, Investor Relations** **(281) 618-4897**

All statements, other than historical facts and 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 the company’s future operations, are forward-looking statements. Although the company believes the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance and actual results or developments may differ materially from those in the forward-looking statements. The company has no obligation and makes no undertaking to publicly update or revise any forward-looking statements, other than to the extent set forth below. 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 the company’s operations, markets, products, services and prices and cause its 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 the company’s 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); the company’s ability to transport its production to the most favorable markets or at all; the timing and extent of the company’s success in discovering, developing, producing and estimating reserves; the economic viability of, and the company’s success in drilling, the company’s large acreage position in the Fayetteville Shale, overall as well as relative to other productive shale gas areas; the company’s ability to fund the company’s planned capital investments; the impact of federal, state and local government regulation, including any legislation relating to hydraulic fracturing, the climate or over the counter derivatives; the company’s ability to determine the most effective and economic fracture stimulation for the Fayetteville Shale and the Marcellus Shale; the costs and availability of oil field personnel services and drilling supplies, raw materials, and equipment and services; the company’s future property acquisition or divestiture activities; increased competition; the financial impact of accounting regulations and critical accounting policies; the comparative cost of alternative fuels; conditions in capital markets, changes in interest rates and the ability of the company’s lenders to provide it with funds as agreed; credit risk relating to the risk of loss as a result of non-performance by the company’s counterparties and any other factors listed in the reports the company has filed and may file with the Securities and Exchange Commission (SEC). For additional information with respect to certain of these and other factors, see the reports filed by the company with the SEC . The company disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Financial Summary Follows

\# # #

The Right People doing the Right Things, wisely investing the cash flow from our underlying Assets, will create Value+®

OPERATING STATISTICS (Unaudited)

Southwestern Energy Company and Subsidiaries

	Three Months		Six Months	
Periods Ended June 30,	**2014**	2013	**2014**	2013
Exploration & Production				
Production				
Gas Production (Bcf)	**189**	160	**371**	307
Oil Production (MBbls)	**47**	24	**63**	65
NGL production (MBbls)	**7**	8	**16**	28
Total equivalent production (Bcfe)	**189**	160	**371**	308
Commodity Prices				
Average realized gas price per Mcf, including hedges	**$ 3.77**	$ 3.87	**$ 3.98**	$ 3.65
Average realized gas price per Mcf, excluding hedges	**$ 3.94**	$ 3.58	**$ 4.28**	$ 3.24
Average oil price per Bbl	**$ 103.27**	$ 99.31	**$ 102.55**	$ 104.11
Average NGL price per Bbl	**$ 37.78**	$ 37.63	**$ 44.36**	$ 45.04
Summary of Derivatives Activity in the Statement of Operations				
Settled Commodity Amounts included in "Operating Revenues"	**$ (25)**	**$** 46	**$ (67)**	**$** 125
Settled Commodity Amounts included in "Gain (Loss) on Derivatives"	**$ (8)**	**$** –	**$ (46)**	**$** 1
Unsettled Commodity Amounts included in "Gain (Loss) on Derivatives"	**$ –**	**$** 93	**$ (62)**	**$** 63
Operating Expenses per Mcfe				
Lease operating expenses	**$ 0.90**	$ 0.85	**$ 0.91**	$ 0.83
General & administrative expenses	**$ 0.23**	$ 0.24	**$ 0.24**	$ 0.23
Taxes, other than income taxes	**$ 0.11**	$ 0.11	**$ 0.12**	$ 0.11
Full cost pool amortization	**$ 1.09**	$ 1.05	**$ 1.10**	$ 1.07
Midstream				
Gas volumes marketed (Bcf)	**225**	189	**441**	369
Gas volumes gathered (Bcf)	**240**	223	**473**	437

STATEMENTS OF OPERATIONS (Unaudited)

Southwestern Energy Company and Subsidiaries

	Three Months		Six Months	
Periods Ended June 30,	**2014**	2013	**2014**	2013
	(in millions, except share/per amounts)			
Operating Revenues				
Gas sales	**$ 717**	$ 614	**$ 1,510**	$ 1,119
Gas marketing	**266**	201	**538**	381
Oil sales	**5**	3	**7**	8
Gas gathering	**47**	44	**93**	87
	1,035	862	**2,148**	1,595
Operating Costs and Expenses				
Gas purchases - midstream services	**261**	200	**532**	380
Operating expenses	**101**	82	**201**	146
General and administrative expenses	**52**	48	**108**	85
Depreciation, depletion and amortization	**230**	187	**455**	366
Taxes, other than income taxes	**24**	20	**50**	41
	668	537	**1,346**	1,018
Operating Income	**367**	325	**802**	577
Interest Expense				
Interest on debt	**25**	25	**50**	49
Other interest charges	**–**	1	**1**	3
Interest capitalized	**(13)**	(17)	**(26)**	(33)
	12	9	**25**	19
Other Gain, Net	**–**	1	**1**	–
Gain (Loss) on Derivatives	**(8)**	93	**(108)**	64
Income Before Income Taxes	**347**	410	**670**	622
Provision for Income Taxes				
Current	**3**	16	**2**	16
Deferred	**137**	148	**267**	233
	140	164	**269**	249
Net Income	**$ 207**	$ 246	**$ 401**	$ 373
Earnings Per Share				
Basic	**$ 0.59**	$ 0.70	**$ 1.14**	$ 1.07
Diluted	**$ 0.59**	$ 0.70	**$ 1.14**	$ 1.06
Weighted Average Common Shares Outstanding				
Basic	**351,391,582**	350,448,806	**351,307,527**	350,241,768
Diluted	**352,579,522**	351,082,807	**352,306,268**	350,911,892

BALANCE SHEETS (Unaudited)

Southwestern Energy Company and Subsidiaries

	June 30, 2014	December 31, 2013
	(in millions)	
ASSETS		
Current Assets	**$ 662**	$ 644
Property and Equipment	**16,551**	15,303
Less: Accumulated depreciation, depletion and amortization	**(8,462)**	(8,006)
	8,089	7,297
Other Long-Term Assets	**136**	107
	8,887	8,048
LIABILITIES AND EQUITY		
Current Liabilities	**886**	688
Long-Term Debt	**1,838**	1,950
Deferred Income Taxes	**1,832**	1,532
Other Long-Term Liabilities	**289**	256
Commitments and Contingencies		
Equity		
Common stock, $0.01 par value; authorized 1,250,000,000 shares; issued 353,161,843 shares in 2014 and 352,938,584 in 2013	**4**	4
Additional paid-in capital	**996**	969
Retained earnings	**3,054**	2,653
Accumulated other comprehensive income	**(12)**	(4)
Total Equity	**4,042**	3,622
	$ 8,887	$ 8,048

STATEMENTS OF CASH FLOWS (Unaudited)

Southwestern Energy Company and Subsidiaries

	Six Months	
Periods Ended June 30,	**2014**	2013
	(in millions)	
Cash Flows From Operating Activities		
Net Income	**$ 401**	$ 373
Adjustment to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	**455**	366
Amortization of debt expense	**2**	2
Deferred income taxes	**267**	233
(Gain) loss on derivatives excluding derivatives, settled	**62**	(63)
Stock-based compensation	**9**	6
Other	**–**	1
Change in assets and liabilities	**(2)**	(40)
Net cash provided by operating activities	**1,194**	878
Cash Flows From Investing Activities		
Capital investments	**(1,144)**	(1,176)
Proceeds from sale of property and equipment	**17**	–
Transfers from restricted cash	**–**	9
Other	**3**	6
Net cash used in investing activities	**(1,124)**	(1,161)
Cash Flows From Financing Activities		
Payments on current portions of long-term debt	**(1)**	(1)
Payments on revolving long-term debt	**(2,486)**	(1,233)
Borrowings under revolving long-term debt	**2,375**	1,463
Change in bank drafts outstanding	**30**	21
Proceeds from exercise of common stock options	**9**	5
Net cash (used in) provided by financing activities	**(73)**	255
Decrease in cash and cash equivalents	**(3)**	(28)
Cash and cash equivalents at beginning of year	**23**	54
Cash and cash equivalents at end of period	**$ 20**	$ 26

SEGMENT INFORMATION (Unaudited)
Southwestern Energy Company and Subsidiaries

	Exploration and Production	Midstream Services	Other	Eliminations	Total
			(in millions)		
Quarter Ending June 30, 2014					
Revenues	**$ 725**	**$ 1,131**	**$ –**	**$ (821)**	**$ 1,035**
Gas purchases	**–**	**976**	**–**	**(715)**	**261**
Operating expenses	**169**	**37**	**1**	**(106)**	**101**
General & administrative expenses	**43**	**9**	**–**	**–**	**52**
Depreciation, depletion & amortization	**216**	**14**	**–**	**–**	**230**
Taxes, other than income taxes	**22**	**2**	**–**	**–**	**24**
Operating income (loss)	**275**	**93**	**(1)**	**–**	**367**
Capital investments (1)	**676**	**36**	**9**	**–**	**721**
Quarter Ending June 30, 2013					
Revenues	$ 619	$ 887	$ –	$ (644)	$ 862
Gas purchases	–	750	–	(550)	200
Operating expenses	135	40	–	(93)	82
General & administrative expenses	40	8	–	–	48
Depreciation, depletion & amortization	174	13	–	–	187
Taxes, other than income taxes	17	3	–	–	20
Operating income (loss)	253	73	–	(1)	325
Capital investments (1)	631	57	7	–	695
Six months Ending June 30, 2014					
Revenues	**$ 1,527**	**$ 2,361**	**$ –**	**$ (1,740)**	**$ 2,148**
Gas purchases	**–**	**2,061**	**–**	**(1,529)**	**532**
Operating expenses	**340**	**72**	**–**	**(211)**	**201**
General & administrative expenses	**89**	**19**	**–**	**–**	**108**
Depreciation, depletion & amortization	**427**	**28**	**–**	**–**	**455**
Taxes, other than income taxes	**44**	**6**	**–**	**–**	**50**
Operating income	**627**	**175**	**–**	**–**	**802**
Capital investments (1)	**1,175**	**75**	**13**	**–**	**1,263**
Six months Ending June 30, 2013					
Revenues	$ 1,129	$ 1,608	$ –	$ (1,142)	$ 1,595
Gas purchases	–	1,342	–	(962)	380
Operating expenses	254	72	–	(180)	146
General & administrative expenses	70	15	–	–	85
Depreciation, depletion & amortization	342	24	–	–	366
Taxes, other than income taxes	35	6	–	–	41
Operating income	428	149	–	–	577
Capital investments (1)	1,107	95	11	–	1,213

(1) Capital investments includes increases of $56 million and $8 million for the three month periods ended June 30, 2014 and 2013, respectively, and increases of $61 million and $40 million for the six month periods ended June 30, 2014 and 2013, respectively, relating to the change in accrued expenditures between periods.

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

Form 10-Q

(Mark One)
[X] Quarterly Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended **June 30, 2014**

Or

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

Commission file number: **1-08246**

Southwestern Energy Company

(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

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

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

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

Class	Outstanding as of July 29, 2014
Common Stock, Par Value $0.01	353,159,739

SOUTHWESTERN ENERGY COMPANY

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FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2014

PART I – FINANCIAL INFORMATION

PART II – OTHER INFORMATION

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

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

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

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

- the timing and extent of changes in market conditions and prices for natural gas and oil (including regional basis differentials);
- our ability to fund our planned capital investments;
- our ability to transport our production to the most favorable markets or at all;
- the timing and extent of our success in discovering, developing, producing and estimating reserves;

- the economic viability of, and our success in drilling, our large acreage position in the Fayetteville Shale and the Marcellus Shale overall as well as relative to other productive shale gas plays and our competitors;
- 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 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;
- the different risks and uncertainties associated with Canadian exploration and production;
- 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, 2013 (the "2013 Annual Report on Form 10-K"), and all quarterly reports on Form 10-Q filed subsequently thereto, including this Form 10-Q ("Form 10-Qs").

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

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

PART I – FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS.

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

	For the three months ended June 30,		For the six months ended June 30,	
	2014	2013	2014	2013
	(in millions, except share/per share amounts)			
Operating Revenues:				
Gas sales	$ 717	$ 614	$ 1,510	$ 1,119
Gas marketing	266	201	538	381
Oil sales	5	3	7	8
Gas gathering	47	44	93	87
	1,035	862	2,148	1,595
Operating Costs and Expenses:				
Gas purchases – midstream services	261	200	532	380
Operating expenses	101	82	201	146
General and administrative expenses	52	48	108	85
Depreciation, depletion and amortization	230	187	455	366
Taxes, other than income taxes	24	20	50	41
	668	537	1,346	1,018
Operating Income	367	325	802	577
Interest Expense:				
Interest on debt	25	25	50	49
Other interest charges	–	1	1	3
Interest capitalized	(13)	(17)	(26)	(33)
	12	9	25	19
Other Gain, Net	–	1	1	–
Gain (Loss) on Derivatives	(8)	93	(108)	64
Income Before Income Taxes	347	410	670	622
Provision for Income Taxes:				
Current	3	16	2	16
Deferred	137	148	267	233
	140	164	269	249
Net Income	$ 207	$ 246	$ 401	$ 373
Earnings Per Share:				
Basic	$ 0.59	$ 0.70	$ 1.14	$ 1.07
Diluted	$ 0.59	$ 0.70	$ 1.14	$ 1.06
Weighted Average Common Shares Outstanding:				
Basic	351,391,582	350,448,806	351,307,527	350,241,768
Diluted	352,579,522	351,082,807	352,306,268	350,911,892

The accompanying notes are an integral part of these
unaudited condensed consolidated financial statements.

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited)

	For the three months ended June 30,		For the six months ended June 30,	
	2014	2013	2014	2013
	(in millions)			
Net income	$ 207	$ 246	$ 401	$ 373
Change in derivatives:				
Settlements [(1)]	15	(28)	40	(75)
Ineffectiveness [(2)]	–	1	1	1
Change in fair value of derivative instruments [(3)]	5	68	(49)	22
Total change in derivatives	20	41	(8)	(52)
Change in value of pension and other postretirement liabilities:				
Amortization of prior service cost included in net periodic pension cost	–	–	–	1
Change in currency translation adjustment	3	(1)	–	(2)
Comprehensive income	$ 230	$ 286	$ 393	$ 320

(1) Net of $10, ($18), $27 and ($50) million in taxes for the three months ended June 30, 2014 and 2013, and six months ended June 30, 2014 and 2013, respectively.

(2) Net of $0, $1, $1 and $0 million in taxes for the three months ended June 30, 2014 and 2013, and six months ended June 30, 2014 and 2013, respectively

(3) Net of $4, $45, ($32) and $15 million in taxes for the three months ended June 30, 2014 and 2013, and six months ended June 30, 2014 and 2013, respectively

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

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

ASSETS	June 30, 2014	December 31, 2013
	(in millions)	
Current assets:		
Cash and cash equivalents	$ 20	$ 23
Accounts receivable	513	464
Inventories	38	38
Derivative assets	40	71
Other current assets	51	48
Total current assets	662	644
Natural gas and oil properties, using the full cost method, including $958 million in 2014 and $957 million in 2013 excluded from amortization	14,440	13,294
Gathering systems	1,381	1,306
Other	730	703
Less: Accumulated depreciation, depletion and amortization	(8,462)	(8,006)
Total property and equipment, net	8,089	7,297
Other long-term assets	136	107
TOTAL ASSETS	$ 8,887	$ 8,048
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 688	$ 507
Taxes payable	66	68
Interest payable	34	33
Current deferred income taxes	–	24
Derivative liabilities	72	7
Other current liabilities	26	49
Total current liabilities	886	688
Long-term debt	1,838	1,950
Deferred income taxes	1,832	1,532
Pension and other postretirement liabilities	17	16
Other long-term liabilities	272	240
Total long-term liabilities	3,959	3,738
Commitments and contingencies (Note 11)		
Equity:		
Common stock, $0.01 par value; authorized 1,250,000,000 shares; issued 353,161,843 shares in 2014 and 352,938,584 in 2013	4	4
Additional paid-in capital	996	969
Retained earnings	3,054	2,653
Accumulated other comprehensive loss	(12)	(4)
Total equity	4,042	3,622
TOTAL LIABILITIES AND EQUITY	$ 8,887	$ 8,048

The accompanying notes are an integral part of these unaudited consolidated financial statements.

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

	For the six months ended June 30, 2014	2013
	(in millions)	
Cash Flows From Operating Activities		
Net income	$ 401	$ 373
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	455	366
Amortization of debt issuance cost	2	2
Deferred income taxes	267	233
(Gain) loss on derivatives excluding derivatives, settled	62	(63)
Stock-based compensation	9	6
Other	–	1
Change in assets and liabilities:		
Accounts receivable	(49)	(68)
Inventories	–	(6)
Accounts payable	53	48
Taxes payable (receivable)	(2)	18
Advances from partners	–	(69)
Other assets and liabilities	(4)	37
Net cash provided by operating activities	1,194	878
Cash Flows From Investing Activities		
Capital investments	(1,144)	(1,176)
Proceeds from sale of property and equipment	17	–
Transfers from restricted cash	–	9
Other	3	6
Net cash used in investing activities	(1,124)	(1,161)
Cash Flows From Financing Activities		
Payments on current portion of long-term debt	(1)	(1)
Payments on revolving long-term debt	(2,486)	(1,233)
Borrowings under revolving long-term debt	2,375	1,463
Change in bank drafts outstanding	30	21
Proceeds from exercise of common stock options	9	5
Net cash (used in) provided by financing activities	(73)	255
Decrease in cash and cash equivalents	(3)	(28)
Cash and cash equivalents at beginning of year	23	54
Cash and cash equivalents at end of period	$ 20	$ 26

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

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

	Common Stock Shares Issued	Common Stock Amount	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total
	(in millions)					
Balance at December 31, 2013	353	$ 4	$ 969	$ 2,653	$ (4)	$ 3,622
Comprehensive income (loss):						
Net income	–	–	–	401	–	401
Other comprehensive loss	–	–	–	–	(8)	(8)
Total comprehensive income (loss)	–	–	–	401	(8)	393
Stock-based compensation	–	–	18	–	–	18
Exercise of stock options	–	–	9	–	–	9
Balance at June 30, 2014	353	$ 4	$ 996	$ 3,054	$ (12)	$ 4,042

The accompanying notes 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

Southwestern Energy Company (including its subsidiaries, collectively, “we”, “Southwestern” or the “Company”) is an independent energy company engaged in natural gas and oil exploration, development and production. The Company engages in natural gas and oil exploration and production, natural gas gathering and natural gas marketing through its subsidiaries. Southwestern’s exploration, development and production (“E&P”) activities are focused within the United States. The Company is actively engaged in exploration and production activities in Arkansas, where we are targeting the unconventional gas reservoir known as the Fayetteville Shale, 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, Louisiana 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, 2013 (“2013 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 2013 Annual Report on Form 10-K.

Certain reclassifications have been made to the prior year financial statements to conform to the 2014 presentation. The effects of the reclassifications were not material to the Company’s unaudited condensed consolidated financial statements.

(2) ACQUISITIONS AND DIVESTITURES

In March 2014, the Company signed an agreement to purchase approximately 306,000 net acres in northwest Colorado principally in the Niobrara formation for approximately $183 million, subject to closing adjustments. The Company utilized its Credit Facility to finance the acquisition. The Company closed on the acquisition on May 1, 2014 and is accounting for it as an asset acquisition.

In April 2013, the Company entered into a definitive purchase agreement to acquire natural gas properties located in Pennsylvania prospective for the Marcellus Shale for approximately $93 million, subject to closing conditions. The Company utilized its revolving credit facility to finance the acquisition. The Company closed on the acquisition during the second quarter of 2013 and accounted for it as an asset acquisition.

(3) PREPAID EXPENSES

The components of prepaid expenses included in other current assets as of June 30, 2014 and December 31, 2013 consisted of the following:

	June 30, 2014	December 31, 2013
	(in millions)	
Prepaid drilling costs	$ 2	$ 9
Prepaid insurance	2	8
Prepaid taxes	12	14
Total	$ 16	$ 31

(4) INVENTORY

Inventory recorded in current assets includes $35 million at June 30, 2014 and $34 million at December 31, 2013 for tubular and other equipment used in the Company's E&P segment, and $2 million at June 30, 2014 and $4 million at December 31, 2013 for natural gas in underground storage owned by the E&P segment.

Other long-term assets include $17 million at June 30, 2014 and $15 million at December 31, 2013, respectively, for inventory held by the Midstream Services segment consisting primarily of pipe that will be used to construct gathering systems.

(5) NATURAL GAS AND OIL PROPERTIES

The Company utilizes the full cost method of accounting for costs related to the exploration, development and acquisition of natural gas and oil reserves. Under this method, all such costs (productive and nonproductive), including salaries, benefits and other internal costs directly attributable to these activities are capitalized on a country by country basis and amortized over the estimated lives of the properties using the units-of-production method. These capitalized costs, less accumulated amortization and related deferred income taxes, are subject to a ceiling test that limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved natural gas and oil reserves, net of taxes, discounted at 10 percent plus the lower of cost or market value of unproved properties. Any costs in excess of the ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, even though higher natural gas and oil prices may subsequently increase the ceiling. Full cost companies must use the average quoted price from the first day of each month from the previous 12 months, including the impact of derivatives qualifying as cash flow hedges, to calculate the ceiling value of their reserves.

Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $4.10 per MMBtu and $96.75 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 June 30, 2014. Cash flow hedges of natural gas production in place increased the ceiling value by $37 million, net of tax, at June 30, 2014. Decreases in average quoted prices, adjusted for market differentials, from June 30, 2014 levels as well as changes in production rates, levels of reserves, capitalized costs, the evaluation of costs excluded from amortization, future development costs, service costs and taxes could result in future ceiling test impairments.

Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $3.44 per MMBtu and $88.13 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 June 30, 2013. Cash flow hedges of natural gas production in place increased the ceiling by $151 million, net of tax, at June 30, 2013.

All of the Company's costs directly associated with the acquisition and evaluation of properties in Canada relating to its exploration program at June 30, 2014 were unproved and did not exceed the ceiling amount. If the exploration program in Canada is unsuccessful on all or a portion of these properties, a ceiling test impairment may result in the future.

(6) EARNINGS PER SHARE

Basic earnings per share is computed by dividing net income (the numerator) by the weighted-average number of common shares outstanding for the period (the denominator). Diluted earnings per share is similarly calculated except that the denominator is increased using the treasury stock method to reflect the potential dilution that could occur if outstanding stock options were exercised and unvested restricted stock and performance unit awards were vested at the end of the applicable period.

The following table presents the computation of earnings per share for the three and six month period ended June 30, 2014 and 2013:

	For the three months ended June 30,		For the six months ended June 30,	
	2014	2013	2014	2013
Net income (in millions)	$ 207	$ 246	$ 401	$ 373
Number of common shares:				
Weighted average outstanding	351,391,582	350,448,806	351,307,527	350,241,768
Issued upon assumed exercise of outstanding stock options	490,302	386,999	418,987	481,528
Effect of issuance of nonvested restricted common stock	577,599	247,002	472,008	188,596
Effect of issuance of nonvested performance units	120,039	–	107,746	–
Weighted average and potential dilutive outstanding (1)(2)	352,579,522	351,082,807	352,306,268	350,911,892
Earnings per share:				
Basic	$ 0.59	$ 0.70	$ 1.14	$ 1.07
Diluted	$ 0.59	$ 0.70	$ 1.14	$ 1.06

(1) Options for 654,189 shares and 19,045 shares of restricted stock were excluded from the calculation for the three months ended June 30, 2014 because they would have had an antidilutive effect. Options for 1,599,246 shares and 29,251 shares of restricted stock were excluded from the calculation for the three months ended June 30, 2013 because they would have had an antidilutive effect.

(2) Options for 1,026,958 shares and 22,952 shares of restricted stock were excluded from the calculation for the six months ended June 30, 2014 because they would have had an antidilutive effect. Options for 2,079,849 shares and 246,347 shares of restricted stock were excluded from the calculation for the six months ended June 30, 2013 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, and is exposed to volatility in interest rates. These risks are managed by the Company's use of certain derivative financial instruments. At June 30, 2014 and December 31, 2013, the Company's derivative financial instruments consisted of fixed price swaps, basis swaps, fixed price call options, and interest rate swaps. A description of the Company's derivative financial instruments is provided below:

Fixed price swaps	The Company receives a fixed price for the contract and pays a floating market price to the counterparty.
Basis swaps	Arrangements that guarantee a price differential for natural gas from a specified delivery point. The Company receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract.
Fixed price call options	The Company sells fixed price call options in exchange for a premium. At the time of settlement, if the market price exceeds the fixed price of the call option, the Company pays the counterparty such excess on sold fixed price call options. If the market price settles below the fixed price of the call option, no payment is due from either party.
Interest rate swaps	Interest rate swaps are used to fix or float interest rates on existing or anticipated indebtedness. The purpose of these instruments is to manage the Company's existing or anticipated exposure to unfavorable interest rate changes.

GAAP requires that all derivatives be recognized in the balance sheet as either an asset or liability and be measured at fair value other than transactions for which normal purchase/normal sale is applied. 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 designated for hedge accounting treatment or that do not meet hedge accounting requirements are recorded in earnings as a component of gain (loss) on derivatives. Within the gain (loss) on derivatives component of the statement of operations are gains (losses) on derivatives excluding derivatives, settled and gains (losses) on derivatives, settled. The Company calculates gains (losses) on derivatives, settled, as the summation of gains and losses on positions which have settled within the period.

The Company utilizes counterparties for its derivative instruments that it believes are creditworthy 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 June 30, 2014 and December 31, 2013:

	Derivative Assets			
	June 30, 2014		December 31, 2013	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
		(in millions)		
Derivatives designated as hedging instruments:				
Fixed price swaps	Derivative assets	$ 11	Derivative assets	$ 21
Fixed price swaps	Other long-term assets	16	Other long-term assets	–
Total derivatives designated as hedging instruments		$ 27		$ 21
Derivatives not designated as hedging instruments:				
Basis swaps	Derivative assets	$ 19	Derivative assets	$ 13
Fixed price swaps	Derivative assets	10	Derivative assets	37
Basis swaps	Other long-term assets	3	Other long-term assets	–
Fixed price swaps	Other long-term assets	16	Other long-term assets	–
Interest rate swaps	Other long-term assets	3	Other long-term assets	8
Total derivatives not designated as hedging instruments		$ 51		$ 58
Total derivative assets		$ 78		$ 79

	Derivative Liabilities			
	June 30, 2014		December 31, 2013	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
		(in millions)		
Derivatives designated as hedging instruments:				
Fixed price swaps	Derivative liabilities	$ 24	Derivative liabilities	$ 4
Total derivatives designated as hedging instruments		$ 24		$ 4
Derivatives not designated as hedging instruments:				
Basis swaps	Derivative liabilities	$ 20	Derivative liabilities	$ 2
Fixed price swaps	Derivative liabilities	9	Derivative liabilities	–
Fixed price call options	Derivative liabilities	16	Derivative liabilities	–
Interest rate swaps	Derivative liabilities	3	Derivative liabilities	2
Basis swaps	Other long-term liabilities	4	Other long-term liabilities	–
Fixed price call options	Other long-term liabilities	37	Other long-term liabilities	30
Interest rate swaps	Other long-term liabilities	3	Other long-term liabilities	3
Total derivatives not designated as hedging instruments		$ 92		$ 37
Total derivative liabilities		$ 116		$ 41

As of June 30, 2014, the Company had fixed price swap derivatives designated as hedges and not designated as hedges on the following volumes of natural gas production (in Bcf):

Year	Fixed price swaps designated for hedge accounting	Fixed price swaps not designated for hedge accounting	Total
2014	142	91	233
2015	120	120	240

Cash Flow Hedges

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

As of June 30, 2014, the Company recorded a net gain in accumulated other comprehensive income related to its hedging activities of $1 million net of a deferred income tax liability of $1 million. The amount recorded in accumulated other comprehensive income will be relieved over time and recognized in the statement of operations as the physical transactions being hedged occur. Assuming the market prices of natural gas futures as of June 30, 2014 remain unchanged, the Company would expect to transfer an aggregate after-tax net loss of $8 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 natural gas sales in the consolidated statements of operations. Volatility in net income, comprehensive income and accumulated other comprehensive income may occur in the future as a result of the Company's derivative activities.

The following tables summarize the before tax effect of all cash flow hedges on the unaudited condensed consolidated financial statements for the three and six month periods ended June 30, 2014 and 2013:

	Gain (Loss) Recognized in Other Comprehensive Income (Effective Portion)			
	For the three months ended June 30,		For the six months ended June 30,	
Derivative Instrument	2014	2013	2014	2013
	(in millions)			
Fixed price swaps	$ 9	$ 113	$ (81)	$ 39

	Classification of Gain (Loss) Reclassified from Accumulated Other Comprehensive Income into Earnings (Effective Portion)	Gain (Loss) Reclassified from Accumulated Other Comprehensive Income into Earnings (Effective Portion)			
		For the three months ended June 30,		For the six months ended June 30,	
Derivative Instrument		2014	2013	2014	2013
		(in millions)			
Fixed price swaps	Gas sales	$ (25)	$ 46	$ (67)	$ 125

	Classification of Loss Recognized in Earnings (Ineffective Portion)	Loss Recognized in Earnings (Ineffective Portion)			
		For the three months ended June 30,		For the six months ended June 30,	
Derivative Instrument		2014	2013	2014	2013
		(in millions)			
Fixed price swaps	Gas sales	$ –	$ (2)	$ (2)	$ (1)

Other Derivative Contracts

For other derivative contracts, 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.

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 are not designated for hedge accounting are recorded on the balance sheet at their fair values under derivative assets, other long-term assets, other current liabilities, and other long-term liabilities, as applicable and all gains and losses related to these contracts are recognized immediately in the consolidated statement of operations as a component of gain (loss) on derivatives.

As of June 30, 2014, the Company had basis swaps on natural gas production that were not designated for hedge accounting of 17 Bcf, 15 Bcf, and 4 Bcf in 2014, 2015, and 2016, respectively.

As of June 30, 2014, the Company had fixed price call options on 200 Bcf and 120 Bcf of natural gas production in 2015 and 2016, respectively, not designated for hedge accounting treatment and fixed price swaps of 91 Bcf and 120 Bcf of natural gas production in 2014 and 2015, respectively, not designated for hedge accounting.

The Company is a party to interest rate swaps that were entered into in order to mitigate the Company's exposure to volatility in interest rates related to construction of its new corporate office complex. The interest rate swaps build to a notional amount of $170 million and expire in June 2020. The Company did not designate the interest rate swaps for hedge accounting. Changes in the fair value of the interest rate swaps are included in gain (loss) on derivatives in the consolidated statements of operations.

The following table summarizes the before tax effect of fixed price swaps, basis swaps, fixed price call options and interest rate swaps not designated for hedge accounting on the condensed consolidated statements of operations for the three and six month period ended June 30, 2014 and 2013:

		Gain (Loss) on Derivatives Excluding Derivatives, Settled Recognized in Earnings			
	Consolidated Statement of Operations	For the three months ended June 30,		For the six months ended June 30,	
Derivative Instrument	Classification of Gain (Loss) on Derivatives Excluding Derivatives, Settled	2014	2013	2014	2013
		(in millions)			
Basis swaps	Gain (Loss) on Derivatives	$ (3)	$ 10	$ (13)	$ 7
Fixed price call options	Gain (Loss) on Derivatives	$ 4	$ 22	$ (23)	$ (35)
Fixed price swaps	Gain (Loss) on Derivatives	$ 2	$ 58	$ (21)	$ 88
Interest rate swaps	Gain (Loss) on Derivatives	$ (3)	$ 3	$ (5)	$ 3

		Gain (Loss) on Derivatives, Settled [(1)] Recognized in Earnings			
	Consolidated Statement of Operations	For the three months ended June 30,		For the six months ended June 30,	
Derivative Instrument	Classification of Gain (Loss) on Derivatives, Settled [(1)]	2014	2013	2014	2013
		(in millions)			
Basis swaps	Gain (Loss) on Derivatives	$ 5	$ –	$ (10)	$ 1
Fixed price swaps	Gain (Loss) on Derivatives	$ (13)	$ –	(36)	–

(1) The Company calculates gain (loss) on derivatives, settled, as the summation of gains and losses on positions that have settled within the period reported.

(8) RECLASSIFICATIONS FROM ACCUMULATED OTHER COMPREHENSIVE LOSS

The following tables detail the components of accumulated other comprehensive loss and the related tax effects for the six months ended June 30, 2014:

	For the six months ended June 30, 2014 (in millions) [1]			
	Gains and Losses on Cash Flow Hedges	Pension and Other Postretirement	Foreign Currency	Total
Balance at December 31, 2013	$ 9	$ (9)	$ (4)	$ (4)
Other comprehensive loss before reclassifications	(49)	–	–	(49)
Amounts reclassified from accumulated other comprehensive loss [2]	41	–	–	41
Net current-period other comprehensive income (loss)	(8)	–	–	(8)
Balance at June 30, 2014	$ 1	$ (9)	$ (4)	$ (12)

(1) All amounts are net of tax.
(2) See separate table below for details about these reclassifications.

The following table details the amounts reclassified from accumulated other comprehensive loss into earnings for the six months ended June 30, 2014:

Details about Accumulated Other Comprehensive Loss	Affected Line Item in the Consolidated Statement of Operations	Amount Reclassified from Accumulated Other Comprehensive Loss For the six months ended June 30, 2014 (in millions)
Gains (losses) on cash flow hedges		
Settlements	Gas sales	$ (67)
Ineffectiveness	Gas sales	(2)
	Income before income taxes	(69)
	Provision for income taxes	(28)
	Net income	$ (41)
Total reclassifications for the period	Net income	$ (41)

(9) FAIR VALUE MEASUREMENTS

The carrying amounts and estimated fair values of the Company's financial instruments as of June 30, 2014 and December 31, 2013 were as follows:

	June 30, 2014		December 31, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Cash and cash equivalents	$ 20	$ 20	$ 23	$ 23
Credit facility	$ 171	$ 171	$ 283	$ 283
Senior notes	$ 1,668	$ 2,044	$ 1,668	$ 1,796
Derivative instruments	$ (38)	$ (38)	$ 38	$ 38

The carrying values of cash and cash equivalents, accounts receivable, accounts payable, other current assets and current liabilities on the unaudited condensed consolidated balance sheets approximate fair value because of their short-term nature. For debt and derivative instruments, the following methods and assumptions were used to estimate fair value:

Debt: The fair values of the Company's 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 1.9% at June 30, 2014 and 2.6% at December 31, 2013, and its 4.10% Senior Notes due 2022, which was 3.2% at June 30, 2014, and 4.2% at December 31, 2013. The carrying value of the borrowings under the Company's Credit Facility at June 30, 2014, approximates fair value because the interest rate is variable and reflective of market rates. The Company considers the fair value of its debt to be a Level 2 measurement on the fair value hierarchy.

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

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

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

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

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

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 swaps and are estimated using internal discounted cash flow calculations using the NYMEX futures index. The Company utilizes discounted cash flow models for valuing its interest rate derivatives. The net derivative values attributable to the Company's interest rate derivative contracts as of June 30, 2014 are based on (i) the contracted notional amounts, (ii) active market-quoted London Interbank Offered Rate ("LIBOR") yield curves and (iii) the applicable credit-adjusted risk-free rate yield curve. The Company's interest rate derivative asset and liability measurements represent Level 2 inputs in the hierarchy. The Company's Level 3 fair value measurements include fixed price call options and basis swaps. The Company's fixed price call options are valued using the Black-Scholes model, an industry standard option valuation model that 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.

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 millions):

	June 30, 2014			
	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	$ –	$ 56	$ 22	$ 78
Derivative liabilities	–	(39)	(77)	(116)
Total	$ –	$ 17	$ (55)	$ (38)

	December 31, 2013			
	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	$ –	$ 66	$ 13	$ 79
Derivative liabilities	–	(9)	(32)	(41)
Total	$ –	$ 57	$ (19)	$ 38

The table below presents reconciliations for the change in net fair value of derivative assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the three and six month periods ended June 30, 2014 and June 30, 2013. The fair values of Level 3 derivative instruments are estimated using proprietary valuation models that utilize both market observable and unobservable parameters. Level 3 instruments presented in the table consist of net derivatives valued using pricing models incorporating assumptions that, in the Company's judgment, reflect the assumptions a reasonable marketplace participant would have used at June 30, 2014 and June 30, 2013.

	For the three months ended June 30,		For the six months ended June 30,	
	2014	2013	2014	2013
	(in millions)			
Balance at beginning of period	$ (56)	$ (60)	$ (19)	$ –
Total gains (losses):				
Included in earnings	6	32	(46)	(27)
Included in other comprehensive income	–	–	–	–
Purchases, issuances, and settlements:				
Purchases	–	–	–	–
Issuances	–	–	–	–
Settlements	(5)	–	10	(1)
Transfers into/out of Level 3	–	–	–	–
Balance at end of period	$ (55)	$ (28)	$ (55)	$ (28)
Change in losses included in earnings relating to derivatives still held as of June 30	$ 1	$ 32	$ (36)	$ (28)

(10) DEBT

The components of debt as of June 30, 2014 and December 31, 2013 consisted of the following:

	June 30, 2014	December 31, 2013
	(in millions)	
Short-term debt:		
7.15% Senior Notes due 2018	$ 1	$ 1
Total short-term debt	1	1
Long-term debt:		
Variable rate (1.50% and 1.64% at June 30, 2014 and December 31, 2013, respectively) Credit Facility, expires December 2018	171	283
7.35% Senior Notes due 2017	15	15
7.125% Senior Notes due 2017	25	25
7.15% Senior Notes due 2018	28	28
7.5% Senior Notes due 2018	600	600
4.10% Senior Notes due 2022	1,000	1,000
Unamortized discount	(1)	(1)
Total long-term debt	1,838	1,950
Total debt	$ 1,839	$ 1,951

Credit Facility

On December 16, 2013, the Company entered into a Credit Agreement ("Credit Facility"), which exchanged our previous revolving credit facility. Under the Credit Facility, we have a borrowing capacity of up to $2.0 billion. The Credit Facility has a maturity date of December 2018 and options for two one-year extensions with participating lender approval. The amount available under the Credit Facility may be increased by $500 million upon the Company's agreement with its participating lenders. The interest rate on the Credit Facility is calculated based upon our credit rating and is currently 137.5 basis points over the current LIBOR. The Credit Facility is unsecured and is not guaranteed by any subsidiaries of the Company. The Credit Facility contains covenants that impose certain restrictions on the Company, including a financial covenant whereby the Company may not issue total debt in excess of 60% of its total adjusted book capital. This financial covenant with respect to capitalization percentages excludes the effects of any full cost ceiling impairments (after December 31, 2011), certain hedging activities and our pension and other postretirement liabilities. As of June 30, 2014, the Company was in compliance with the covenants of its Credit Facility and other debt agreements. Although 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.

(11) 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 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 $45 million Canadian dollars. 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 perform fully, the Minister of Finance may retain a portion of the applicable promissory notes in an amount equal to any deficiency. The Company commenced its Canada exploration program in 2010 and, as of June 30, 2014 has invested $43 million Canadian dollars, or $41 million US dollars, in New Brunswick towards the Company's commitment. In December 2012, the Company received two one-year extensions to our exploration license agreements, the second of which will expire on March 16, 2015. No liability has been recognized in connection with the promissory notes due to the Company's investments in New Brunswick as of June 30, 2014 and its future investment plans.

The Company entered into new and amended natural gas transportation and gathering arrangements with third party pipelines, during the second quarter of 2014, in support of the Company's production in the Marcellus Shale. As of June 30, 2014, the Company's obligations for demand and similar charges under the firm transportation agreements and gathering agreements totaled approximately $3.8 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

Tovah Energy

In February 2009, Southwestern Energy Production Company ("SEPCO") was added as a defendant in a case then styled Tovah Energy, LLC and Toby Berry-Helfand v. David Michael Grimes, et, al., pending in the 273rd District Court in Shelby County, Texas. By the time of trial in December 2010, Ms. Berry-Helfand (the only remaining plaintiff) alleged that, in 2005, she 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, she alleged 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 2005 and February 2006. She also sought disgorgement of SEPCO's profits. A former associate of the plaintiff intervened in the matter claiming to have helped develop the prospect years earlier.

The jury found in favor of the plaintiff and the intervenor with respect to all of the statutory and common law claims and awarded $11 million in compensatory damages but no special, punitive or other damages. Separately, the jury determined that SEPCO's profits for purposes of disgorgement, if ordered as a remedy, were $382 million. (Disgorgement of profits is an equitable remedy determined by the judge, and it is within the judge's discretion to award none, some or all of unlawfully obtained profits.) In August 2011, a judgment was entered pursuant to which the plaintiff and the intervenor were entitled to recover approximately $11 million in actual damages and approximately $24 million in disgorgement as well as prejudgment interest and attorneys' fees, which currently are estimated to be up to $9 million, and all costs of court of the plaintiff and intervenor.

Both sides appealed and in July 2013, the Texas Court of Appeals in Tyler ordered that (1) the judgment awarding the plaintiff and the intervenor $24 million as disgorgement of illicit gains be reversed and judgment rendered that they take nothing, (2) the award of $11 million for actual damages, insofar as it is based on the jury's findings of breach of fiduciary duty, fraud, breach of contract, and theft of trade secret be reversed and judgment rendered that the plaintiff and the intervenor take nothing under those theories of recovery, (3) the award of $11 million to the plaintiff and the intervenor as damages for misappropriation of trade secret be affirmed, (4) the case be remanded to the trial court for a determination and award of attorney's fees for SEPCO as the prevailing party under the Texas Theft Liability Act, and (5) in all other respects, the judgment is affirmed. All parties petitioned for rehearing. The Court of Appeals denied rehearing in November 2013.

SEPCO filed a petition for review in the Supreme Court of Texas in February 2014. The plaintiff and the intervenor filed cross-petition for review in April 2014, but conditioned their filing on the court's granting SEPCO's petition for review; i.e., if the court denies SEPCO's petition for review, then the plaintiff and the intervenor are not seeking further review of the court of appeals' judgment. Based on the Company's understanding and judgment of the facts and merits of this case, including appellate matters, and after considering the advice of counsel, the Company has determined that, although reasonably possible, a materially adverse final outcome to this action is not probable. As such, the Company has not accrued any amounts with respect to this action. If the Supreme Court declines to hear the case or affirms all aspects of the court of appeals' judgment, then SEPCO would owe the $11 million in damages, plus interest and attorneys fees, offset by any award of attorneys' fees for its prevailing on the theft count. The Company's assessment may change in the future due to occurrence of certain events, such as the result of the petition or petitions for review at the Supreme Court of Texas, and such a 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.

Other

The Company is subject to various litigation, claims and proceedings that have arisen in the ordinary course of business, such as for alleged breaches of contract, miscalculation of royalties and pollution, contamination or nuisance. Management believes that such litigation, claims and proceedings, individually or in aggregate and after taking into account insurance, are not likely to have a material adverse impact on our financial position, results of operations or cash flows. Many of these matters are in early stages, so the allegations and the damage theories have not been fully developed, and all subject to inherent uncertainties; therefore, 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 the Company's financial position, results of operations or cash flows for the period in which the effect becomes reasonably estimable. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated.

(12) SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION

Supplemental disclosures of cash flow information:

	For the three months ended June 30,		For the six months ended June 30,	
	2014	2013	2014	2013
	(in millions)			
Cash paid for interest	$ 5	$ 6	$ 50	$ 50
Cash paid for income taxes	$ –	$ 1	$ –	$ 17
Noncash property changes	$ 60	$ 10	$ 70	$ 46

(13) PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

The Company has defined pension and postretirement benefit plans which cover substantially all of the Company's employees. Net periodic pension and other postretirement benefit costs include the following components for the three and six month periods ended June 30, 2014 and 2013:

	Pension Benefits			
	For the three months ended June 30,		For the six months ended June 30,	
	2014	2013	2014	2013
	(in millions)			
Service cost	$ 3	$ 4	$ 7	$ 7
Interest cost	2	1	3	2
Expected return on plan assets	(2)	(2)	(4)	(3)
Amortization of prior service cost	–	–	–	–
Amortization of net loss	–	–	–	1
Net periodic benefit cost	$ 3	$ 3	$ 6	$ 7

The Company's postretirement benefit plan had a net periodic benefit cost of $1, $1, $2 and $1 million as of the three months ended June 30, 2014 and 2013 and six months ended June 30, 2014 and 2013, respectively. As of June 30, 2014, the Company has contributed $6 million to the pension plan, and expects to contribute an additional $6 million to the pension plan in 2014.

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 10,776 shares at June 30, 2014 compared to 9,924 shares at December 31, 2013.

(14) STOCK-BASED COMPENSATION

The Company recognized the following amounts in employee stock-based compensation costs for the three and six months ended June 30, 2014 and 2013:

	For the three months ended June 30,		For the six months ended June 30,	
	2014	2013	2014	2013
	(in millions)			
Stock-based compensation cost – expensed	$ 4	$ 3	$ 9	$ 6
Stock-based compensation cost – capitalized	$ 4	$ 3	$ 9	$ 6

As of June 30, 2014, there was $74 million of total unrecognized compensation cost related to the Company's unvested stock option grants, restricted stock grants, and performance units. This cost is expected to be recognized over a weighted-average period of 3 years.

The following table summarizes stock option activity for the six months ended June 30, 2014 and provides information for options outstanding and options exercisable as of June 30, 2014:

	Number of Options	Weighted Average Exercise Price
	(in thousands)	
Outstanding at December 31, 2013	3,313	$ 35.70
Granted	90	46.55
Exercised	(269)	32.23
Forfeited or expired	(64)	38.45
Outstanding at June 30, 2014	3,070	36.26
Exercisable at June 30, 2014	1,851	$ 35.35

The following table summarizes restricted stock activity for the six months ended June 30, 2014 and provides information for unvested shares as of June 30, 2014:

	Number of Shares	Weighted Average Grant Date Fair Value
	(in thousands)	
Unvested shares at December 31, 2013	1,771	$ 37.55
Granted	22	46.05
Vested	(15)	36.48
Forfeited	(67)	37.94
Unvested shares at June 30, 2014	1,711	$ 37.65

The following table summarizes performance unit activity to be paid out in Company stock for the six months ended June 30, 2014 and provides information for unvested units as of June 30, 2014. The performance units include a market condition based on Relative Total Shareholder Return ("TSR") and a performance condition based on the Company's Present Value Index ("PVI"). The fair value of the TSR market condition of the performance units is based on a Monte Carlo model and is amortized to compensation expense on a straight-line basis over the vesting period of the award. The fair value of the PVI performance condition of the performance units is based on the closing price of the Company's common stock at the grant date and amortized to compensation expense on a straight line basis over the vesting period of the award.

	Number of Units	Weighted Average Grant Date Fair Value
	(in thousands)	
Unvested units at December 31, 2013	–	$ –
Granted	359	40.44
Vested	–	–
Forfeited	–	–
Unvested units at June 30, 2014	359	$ 40.44

Liability-Classified Performance Units

Certain employees were provided performance units vesting equally over three years. The payout of these units is based on certain metrics, such as total shareholder return and reserve replacement efficiency, compared to a predetermined group of peer companies and Company goal. At the end of each performance period, the value of the vested performance units, if any, is paid in cash. As of June 30, 2014 and December 31, 2013, the Company's liability under the performance unit agreements was $39 million and $45 million, respectively.

(15) SEGMENT INFORMATION

The Company's reportable business segments have been identified based on the differences in products or services provided. Revenues for the E&P segment are derived from the production and sale of natural gas and crude oil. The Midstream Services segment generates revenue through the marketing of both Company and third-party produced 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 2013 Annual Report on Form 10-K. Management evaluates the performance of its segments based on operating income, defined as operating revenues less operating costs. Income before income taxes, for the purpose of reconciling the operating income amount shown below to consolidated income before income taxes, is the sum of operating income, interest expense and interest and other income (loss). The "Other" column includes items not related to the Company's reportable segments including real estate and corporate items.

	Exploration and Production	Midstream Services	Other	Total
	(in millions)			
Three months ended June 30, 2014:				
Revenues from external customers	$ 721	$ 314	$ –	$ 1,035
Intersegment revenues	4	817	–	821
Operating income (loss)	275	93	(1)	367
Loss on derivatives	(7)	(1)	–	(8)
Depreciation, depletion and amortization	216	14	–	230
Interest expense(1)	10	2	–	12
Provision for income taxes(1)	105	35	–	140
Assets	7,127	1,532	228 (2)	8,887
Capital investments(3)	676	36	9	721
Three months ended June 30, 2013:				
Revenues from external customers	$ 617	$ 245	$ –	$ 862
Intersegment revenues	2	642	(1)	643
Operating income (loss)	253	73	(1)	325
Other gain, net	1	–	–	1
Gain on derivatives	93	–	–	93
Depreciation, depletion and amortization	174	13	–	187
Interest expense(1)	6	3	–	9
Provision for income taxes(1)	138	26	–	164
Assets	6,006	1,384	245 (2)	7,635
Capital investments(3)	631	57	7	695

	Exploration and Production	Midstream Services	Other	Total
		(in millions)		
Six months ended June 30, 2014:				
Revenues from external customers	$ 1,517	$ 631	$ –	$ 2,148
Intersegment revenues	10	1,730	–	1,740
Operating income	627	175	–	802
Other gain, net	1	–	–	1
Loss on derivatives	(107)	(1)	–	(108)
Depreciation, depletion and amortization	427	28	–	455
Interest expense[1]	18	7	–	25
Provision for income taxes[1]	202	67	–	269
Assets	7,127	1,532	228 [2]	8,887
Capital investments[3]	1,175	75	13	1,263
Six months ended June 30, 2013:				
Revenues from external customers	$ 1,126	$ 469	$ –	$ 1,595
Intersegment revenues	3	1,139	–	1,142
Operating income	428	149	–	577
Gain on derivatives	64	–	–	64
Depreciation, depletion and amortization	342	24	–	366
Interest expense[1]	14	5	–	19
Provision for income taxes[1]	194	55	–	249
Assets	6,006	1,384	245 [2]	7,635
Capital investments[3]	1,107	95	11	1,213

(1) 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 for non reportable segments.
(3) Capital investments includes increases of $56 million and $8 million for the three month periods ended June 30, 2014 and 2013, respectively, and increases of $61 million and $40 million for the six month periods ended June 30, 2014 and 2013, respectively, relating to the change in accrued expenditures between periods.

Included in intersegment revenues of the Midstream Services segment are $725 million and $559 million for the three months ended June 30, 2014 and 2013, respectively, and $1,549 million and $979 million for the six months ended June 30, 2014 and 2013, 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. At June 30, 2014, E&P segment assets included $85 million and at June 30, 2013, E&P segment assets included $51 million related to the Company's activities in Canada.

(16) NEW ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

In May 2014, the FASB issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (Topic 606) ("Update 2014-09"), which seeks to provide clarity for recognizing revenue. Topic 606 Revenue from Contracts with Customers will supersede the revenue recognition requirements in Topic 605 Revenue Recognition. Update 2014-09 requires an entity to recognize revenue to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled for those goods or services. Entities may apply the amendments in Update 2014-09 either (a) retrospectively to each prior reporting period presented, and the entity may elect a practical expedient per the Update, or (b) retrospectively with the cumulative effect of initially applying Update 2014-09 recognized at the date of initial application - if an entity elects this transition method it also should provide the additional disclosures in reporting periods. For public entities, Update 2014-09 is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. We are currently evaluating the provisions of Update 2014-09 and assessing the impact, if any, it may have on the Company's consolidated results of operations, financial position or cash flows.

In June 2014, the FASB issued Accounting Standards Update No. 2014-12, Compensation-Stock Compensation (Topic 718): Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could be Achieved After the Requisite Service Period ("Update 2014-12"), which clarifies the accounting treatment of such awards in practice. Update 2014-12 requires that a performance target that affects vesting and that could be achieved after the requisite service period be treated as a performance condition. Entities may apply the amendments in Update 2014-12 either (a) prospectively to all awards granted or modified after the effective date, or (b) retrospectively to all awards with performance targets that are outstanding as of the beginning of the earliest annual period presented in the financial statements and to all new or modified awards thereafter. Update 2014-12 is effective for annual periods and interim periods within those annual periods beginning after December 15, 2015, and early adoption is permitted. We are currently evaluating the provisions of Update 2014-12 and assessing the impact, if any, it may have on the Company's consolidated results of operations, financial position or cash flows.

(17) CONDENSED CONSOLIDATING FINANCIAL INFORMATION

As of December 16, 2013, following the release of all guarantees under the 7.15%, 7.5%, 7.35%, 7.125%, and 4.10% Senior Notes and our former revolving credit facility upon entering into the new Credit Facility, all of our wholly-owned subsidiaries have been released of their guarantees. Prior to that date, the Company's obligation under registered public debt and outstanding senior notes as listed in Note 10 were fully and unconditionally guaranteed, jointly and severally, by all of our wholly-owned subsidiaries, other than minor subsidiaries, on a senior unsecured basis, and the Company, as a parent company, had no independent assets or operations. The subsidiary guarantees (i) ranked equally in right of payment with all of the existing and future senior debt of the subsidiary guarantors; (ii) ranked senior to all of the existing and future subordinated debt of the subsidiary guarantors; (iii) were 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) were structurally subordinated to all debt and other obligations of the subsidiaries of the guarantors. In the case of each series of notes, if no default or event of default had occurred and was continuing, these guarantees would have been released (i) automatically upon any sale, exchange or transfer of all the Company's interest 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 obligation under the Company's revolving credit facility; and (iv) upon legal or covenant defeasance or other satisfaction of the obligations under the notes. In addition, there were no significant restrictions on the ability of the Company or a guarantor to obtain funds from its subsidiaries by dividend or loan, and none of the assets of the Company or a guarantor represented restricted net assets pursuant to rule 4-08(e)(3) of Regulation S-X under the Securities Act of 1933, as amended.

The Company is providing condensed consolidating financial information for SEECO, SEPCO, and SES, its subsidiaries that were guarantors of the Company's registered public debt and outstanding senior notes, and for its other subsidiaries that were not guarantors of such debt for the three and six months ended June 30, 2013, as applicable. The Company has not provided comparative financial statements for 2014 because all guarantees were released in 2013. The Company has not presented separate financial and narrative information for each of the former subsidiary guarantors because it believes that such financial and narrative financial 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 and cash flow for the Company's former guarantors and other subsidiaries.

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Unaudited)

	Parent	Former Guarantors	Other Subsidiaries	Eliminations	Consolidated
			(in millions)		
Three months ended June 30, 2013:					
Operating revenues	$ –	$ 818	$ 127	$ (83)	$ 862
Operating costs and expenses:					
Gas purchases	–	200	–	–	200
Operating expenses	–	125	40	(83)	82
General and administrative expenses	–	41	7	–	48
Depreciation, depletion and amortization	–	175	12	–	187
Taxes, other than income taxes	–	17	3	–	20
Total operating costs and expenses	–	558	62	(83)	537
Operating income	–	260	65	–	325
Other income, net	–	–	1	–	1
Gain on derivatives	–	93	–	–	93
Equity in earnings of subsidiaries	246	–	–	(246)	–
Interest expense	–	7	2	–	9
Income (loss) before income taxes	246	346	64	(246)	410
Provision for income taxes	–	142	22	–	164
Net income	246	204	42	(246)	246
Comprehensive income (loss)	$ 286	$ 245	$ 40	$ (285)	$ 286

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Unaudited)

	Parent	Former Guarantors	Other Subsidiaries	Eliminations	Consolidated
			(in millions)		
Six months ended June 30, 2013:					
Operating revenues	$ –	$ 1,508	$ 248	$ (161)	$ 1,595
Operating costs and expenses:					
Gas purchases – midstream services	–	381	–	(1)	380
Operating expenses	–	234	72	(160)	146
General and administrative expenses	–	73	12	–	85
Depreciation, depletion and amortization	–	342	24	–	366
Taxes, other than income taxes	–	35	6	–	41
Total operating costs and expenses	–	1,065	114	(161)	1,018
Operating income (loss)	–	443	134	–	577
Gain on derivatives	–	64	–	–	64
Equity in earnings of subsidiaries	373	–	–	(373)	–
Interest expense	–	15	4	–	19
Income (loss) before income taxes	373	492	130	(373)	622
Provision for income taxes	–	200	49	–	249
Net income (loss)	373	292	81	(373)	373
Comprehensive income (loss)	$ 320	$ 239	$ 79	$ (318)	$ 320

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Unaudited)

	Parent	Former Guarantors	Other Subsidiaries	Eliminations	Consolidated
			(in millions)		
Six months ended June 30, 2013:					
Net cash provided by (used in) operating activities	$ (29)	$ 651	$ 256	$ –	$ 878
Investing activities:					
Capital investments	(13)	(1,084)	(79)	–	(1,176)
Transfers from restricted cash	9	–	–	–	9
Other	–	2	4	–	6
Net cash used in investing activities	(4)	(1,082)	(75)	–	(1,161)
Financing activities:					
Intercompany activities	(244)	425	(181)	–	–
Payments on current portion of long-term debt	(1)	–	–	–	(1)
Payments on revolving long-term debt	(1,233)	–	–	–	(1,233)
Borrowings under revolving long-term debt	1,463	–	–	–	1,463
Other items	26	–	–	–	26
Net cash provided by (used in) financing activities	11	425	(181)	–	255
Decrease in cash and cash equivalents	(22)	(6)	–	–	(28)
Cash and cash equivalents at beginning of year	48	6	–	–	54
Cash and cash equivalents at end of period	$ 26	$ –	$ –	$ –	$ 26

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 2013 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, 2014 and 2013. 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 2013 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 2013 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 oil exploration, development and production, or E&P. We are also focused on creating and capturing additional value through our natural gas gathering and marketing businesses, which we refer to as Midstream Services. We operate principally in two segments: E&P and Midstream Services.

Our primary business is the exploration for and production of natural gas and oil, with our current operations being focused within the United States. We are actively engaged in exploration and production activities in Arkansas, where we are targeting the unconventional gas reservoir known as the Fayetteville Shale, 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. We derive the majority of our operating income and cash flow from the natural gas production of our E&P business and expect this to continue in the future. We expect that growth in our operating income and revenues will depend primarily 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 and the Marcellus Shale. 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 volatility in natural gas prices as evidenced by New York Mercantile Exchange, or 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 sales prices for our production. In addition to the factors identified above, the prices we realize for our production are affected by our hedging activities, transportation costs as well as locational differences in market prices.

Three Months Ended June 30, 2014 Compared with Three Months Ended June 30, 2013

We reported net income of $207 million for the three months ended June 30, 2014, or $0.59 per diluted share, compared to net income of $246 million, or $0.70 per diluted share, for the comparable period in 2013. For the three months ended June 30, 2014, the Company had a mark to market loss on derivatives of $8 million. Excluding mark to market derivatives, settled, this loss was less than $1 million. Excluding the effect of an approximate 40% tax rate, this loss did not impact net income of $207 million resulting in adjusted net income of $207 million for the three months ended June 30, 2014. For the three months ended June 30, 2013, the Company had a mark to market gain on derivatives of $93 million. Excluding the effect of an approximate 40% tax rate, this gain was $56 million. Net income of $246 million less the tax effected gain of $56 million results in adjusted net income of $190 million for the three months ended June 30, 2013.

Our natural gas and oil production increased to 189 Bcfe for the three months ended June 30, 2014, up 18% from 160 Bcfe for the three months ended June 30, 2013. This 29 Bcfe increase was due to a 27 Bcf increase in net production from our Marcellus Shale properties and a 2 Bcf increase in net production from our other properties. The average price realized for our gas production, including the effects of hedges, decreased 3% to $3.77 per Mcf for the three months ended June 30, 2014 compared to $3.87 per Mcf for the same period in 2013.

Our E&P segment reported operating income of $275 million for the three months ended June 30, 2014, up from operating income of $253 million for the three months ended June 30, 2013. This increase was a result of an increase in revenue impact of our 18%, or 29 Bcfe, increase in production, which more than offset the 3%, or $0.10 per Mcf, decrease in our realized natural gas prices and the $84 million increase in operating costs and expenses that resulted from increased activity levels.

Operating income for our Midstream Services segment was $93 million for the three months ended June 30, 2014, up from $73 million for the three months ended June 30, 2013, due to an increase of $12 million in gas gathering revenues, an increase of $6 million in the margin generated from our natural gas marketing activities, and a $2 million decrease in operating costs and expenses.

Capital investments were $721 million for the three months ended June 30, 2014, of which $676 million was invested in our E&P segment, compared to $695 million for the same period of 2013, of which $631 million was invested in our E&P segment.

Six Months Ended June 30, 2014 Compared with Six Months Ended June 30, 2013

We reported net income of $401 million for the six months ended June 30, 2014, or $1.14 per diluted share, compared to net income of $373 million, or $1.06 per diluted share, for the comparable period in 2013. For the six months ended June 30, 2014, the Company had a mark to market loss on derivatives of $108 million. Excluding mark to market derivatives, settled, this loss was $62 million. Excluding the effect of an approximate 40% tax rate, this loss was $37 million. Net income of $401 million plus the tax effected loss of $37 million results in adjusted net income of $438 million for the six months ended June 30, 2014. For the six months ended June 30, 2013, the Company had a mark to market gain on derivatives of $64 million. Excluding mark to market derivatives, settled, this gain was $63 million. Excluding the effect of an approximate 40% tax rate, this gain was $38 million. Net income of $373 million less the tax effected gain of $38 million results in adjusted net income of $335 million.

Our natural gas and oil production increased to 371 Bcfe for the six months ended June 30, 2014, up 20% from 308 Bcfe for the six months ended June 30, 2013. This 63 Bcfe increase was due to a 61 Bcf increase in net production from our Marcellus Shale properties and a 3 Bcf increase in net production from our Fayetteville Shale properties, which more than offset a 1 Bcfe decrease in net production from our other properties. The average price realized for our gas production, including the effects of hedges, increased 9% to $3.98 per Mcf for the six months ended June 30, 2014 compared to $3.65 per Mcf for the same period in 2013.

Our E&P segment reported operating income of $627 million for the six months ended June 30, 2014, up from an operating income of $428 million for the six months ended June 30, 2013. This increase was a result of the revenue impact of our 20%, or 63 Bcfe, increase in production and a 9%, or $0.33 per Mcf, increase in our realized natural gas prices, offset by an increase in operating costs and expenses of $199 million associated with the expansion of our E&P operations due to the continued development of our Fayetteville Shale assets and Marcellus Shale assets.

Operating income for our Midstream Services segment was $175 million for the six months ended June 30, 2014, up from $149 million for the six months ended June 30, 2013, due to an increase of $25 million in gas gathering revenues and an increase of $9 million in the margin generated from our gas marketing activities, which was partially offset by a $8 million increase in operating costs and expenses associated with an increase in gas volumes gathered, exclusive of gas purchase costs.

Net cash provided by operating activities increased 36% to $1,194 million for the six months ended June 30, 2014, up from $878 million for the same period in 2013, 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, higher realized gas prices, and an increase in changes in working capital. Capital investments were $1,263 million for the six months ended June 30, 2014, of which $1,175 million was invested in our E&P segment, compared to $1,213 million for the same period of 2013, of which $1,107 million was invested in our E&P segment.

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,	
	2014	2013	2014	2013
	($ in millions, except per unit amounts)			
Revenues	$ 725	$ 619	$ 1,527	$ 1,129
Operating costs and expenses	$ 450	$ 366	$ 900	$ 701
Operating income	$ 275	$ 253	$ 627	$ 428
Gain (loss) on derivatives [(1)]	$ (7)	$ –	$ (45)	$ 1
Gas production (Bcf)	189	160	371	307
Oil production (MBbls)	47	24	63	65
NGL production (MBbls)	7	8	16	28
Total production (Bcfe)	189	160	371	308
Average realized gas price per Mcf, including hedges [(2)]	$ 3.77	$ 3.87	$ 3.98	$ 3.65
Average realized gas price per Mcf, excluding hedges	$ 3.94	$ 3.58	$ 4.28	$ 3.24
Average oil price per Bbl	$ 103.27	$ 99.31	$ 102.55	$ 104.11
Average NGL price per Bbl	$ 37.78	$ 37.63	$ 44.36	$ 45.04
Average unit costs per Mcfe:				
Lease operating expenses	$ 0.90	$ 0.85	$ 0.91	$ 0.83
General & administrative expenses	$ 0.23	$ 0.24	$ 0.24	$ 0.23
Taxes, other than income taxes	$ 0.11	$ 0.11	$ 0.12	$ 0.11
Full cost pool amortization	$ 1.09	$ 1.05	$ 1.10	$ 1.07

(1) Represents the gain (loss) on derivatives, settled, associated with derivatives not designated or not qualifying for hedge accounting.

(2) Including the gain (loss) on derivatives excluding derivatives, settled effects of commodity hedging contracts not designated for hedge accounting, results in an average price of $3.79, $4.42, $3.82, and $3.85 per Mcf for the three months ended June 30, 2014 and 2013, and the six months ended June 30, 2014 and 2013, respectively.

Revenues

Revenues for our E&P segment were $725 million for the three months ended June 30, 2014, up $106 million, or 17%, compared to the same period in 2013. Higher natural gas production volume increased revenues by $111 million and was partially offset by a decrease of $8 million due to a slight decline in the prices realized from the sale of our natural gas. E&P revenues were $1.5 billion for the six months ended June 30, 2014, up $398 million, or 35%. The increase in revenue was driven by a $231 million increase from higher natural gas production volumes and a $167 million increase from higher realized prices from the sale of our natural gas production. We expect our natural gas production volumes to continue to increase due to our development and growth of our shale properties. Natural gas prices are difficult to predict and subject to wide price fluctuations. As of June 30, 2014, we had hedged 233 Bcf of our remaining 2014 natural gas production and 240 Bcf of our 2015 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 June 30, 2014, our natural gas and oil production increased 18% to 189 Bcfe, up from 160 Bcfe from the same period in 2013, and was produced entirely by our properties in the United States. The 29 Bcfe increase in our 2014 production was due to a 27 Bcf increase in net production from our Marcellus Shale properties and a 2 Bcf increase in net production from our other properties. Net production from our Fayetteville Shale and Marcellus Shale properties was 124 Bcf and 61 Bcf, respectively, for the three months ended June 30, 2014 compared to 121 Bcf and 34 Bcf, respectively, for the same period in 2013. For the six months ended June 30, 2014, our natural gas and oil production increased 20% to 371 Bcfe, up from 308 Bcfe from the same period in 2013, and was produced entirely by our properties in the United States. The 63 Bcfe increase in our 2014 production was due to a 61 Bcf increase in net natural gas production from our Marcellus Shale properties and a 3 Bcf increase in net production from our Fayetteville Shale assets, which more than offset a 1 Bcfe decrease in our other properties. Net production from our Fayetteville Shale and Marcellus Shale properties was 243 Bcf and 119 Bcf, respectively, for the six months ended June 30, 2014 compared to 240 Bcf and 57 Bcf, respectively, for the same period in 2013.

Commodity Prices

The average price realized for our natural gas production, including the effects of hedges, decreased to $3.77 per Mcf for the three months ended June 30, 2014, as compared to $3.87 for the same period in 2013. The decrease was the result of a $0.46 per Mcf decrease from the impact of our price hedging activities, which was partially offset by a $0.36 per Mcf increase in the average natural gas prices, excluding hedges. The average price realized for our natural gas production, excluding the effects of hedges, increased 10% to $3.94 per Mcf for the three months ended June 30, 2014, as compared to the same period in 2013. Our hedges decreased the average realized natural gas price $0.17 per Mcf for the three months ended June 30, 2014 compared to an increase of $0.29 per Mcf for the same period in 2013. The average price realized for our natural gas production, including the effects of hedges, increased 9% to $3.98 per Mcf for the six months ended June 30, 2014, as compared to the same period in 2013. The increase in the average price realized for six months ended June 30, 2014, as compared to the same period in 2013, primarily reflects the $1.04 per Mcf increase in average gas prices, excluding hedges, which was partially offset by the effect of hedging activities. Our hedging activities decreased the average natural gas price $0.30 per Mcf for the six months ended June 30, 2014 compared to an increase of $0.41 per Mcf for the same period in 2013. 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, “Quantitative and Qualitative Disclosures about market Risks” and Note 7 to the unaudited condensed consolidated financial statements included in this Form 10-Q for additional discussion.

Our E&P segment typically 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, 2014 of $4.28 per Mcf was approximately $0.52 lower than the average monthly NYMEX settlement price, primarily due to locational basis differentials and transportation costs. We protected approximately 48% of our natural gas production for the six months ended June 30, 2014 from the impact of widening basis differentials through our hedging activities and sales arrangements. For 2014, we expect our total natural gas sales discount to NYMEX to be approximately $0.54 to $0.59 per Mcf. At June 30, 2014, we had basis protected on approximately 163 Bcf of our remaining 2014 expected natural gas production through financial hedging activities and physical sales arrangements at a differential to NYMEX natural gas prices of approximately ($0.08) per Mcf, excluding transportation and fuel charges. Additionally, at June 30, 2014, we had basis protected on approximately 97 Bcf and 46 Bcf of our 2015 and 2016 expected natural gas production, respectively, through financial hedging activities and physical sales arrangements.

In addition to the basis hedges discussed above, at June 30, 2014, we had NYMEX fixed price hedges in place on notional volumes of 233 Bcf of our remaining 2014 natural gas production at an average price of $4.35 per MMBtu and notional volumes of 240 Bcf of our 2015 natural gas production at an average price of $4.40 per MMBtu.

Operating Income

Our E&P segment reported operating income of $275 million for the three months ended June 30, 2014, up from operating income of $253 million for the three months ended June 30, 2013. This increase was as a result of the revenue impact of our 18%, or 29 Bcfe, increase in production, which more than offset the 3%, or $0.10 per Mcf, decrease in our realized natural gas prices and the $84 million increase in operating costs and expenses that resulted from increased activity levels. Our E&P segment reported operating income of $627 million for the six months ended June 30, 2014, up from an operating income of $428 million for the six months ended June 30, 2013. This increases was as a result of the revenue impact of our 20%, or 63 Bcfe, increase in production and a 9%, or $0.33 per Mcf, increase in our realized natural gas prices, offset by an increase in operating costs and expenses of $199 million associated with the expansion of our E&P operations due to the continued development of our Fayetteville Shale assets and Marcellus Shale assets.

Operating Costs and Expenses

Lease operating expenses per Mcfe for our E&P segment were $0.90 for the three months ended June 30, 2014 compared to $0.85 for the same period in 2013. Lease operating expenses per Mcfe for our E&P segment were $0.91 for the six months ended June 30, 2014 compared to $0.83 for the same period in 2013. The increase in lease operating expense per unit of production for the three and six months ended June 30, 2014 as compared to the same period of 2013 was primarily due to an increase in gathering costs in our Marcellus Shale assets and an increase in compression costs.

General and administrative expenses per Mcfe for our E&P segment were $0.23 for the three months ended June 30, 2014 compared to $0.24 for the same period in 2013 primarily due to a larger increase in production volumes compared to the increase in personnel costs. General and administrative expenses per Mcfe were $0.24 for the six months ended June 30, 2014 compared to $0.23 for same period in 2013 primarily due to an increase in personnel costs. In total general and administrative expenses for our E&P segment were $43 million for the three months ended June 30, 2014 compared to $39 million for the same period in 2013, primarily due to increased personnel costs associated with the expansion of our E&P operations due to the continued development of our Fayetteville Shale assets and Marcellus Shale assets. In total general and administrative expenses for our E&P segments were $89 million for the six months ended June 30, 2014 compared to $70 million for the same period in 2013. This increase was primarily due to increased personnel costs associated with the expansion of our E&P operations due to the continued development of our Fayetteville Shale assets and Marcellus Shale assets.

Taxes other than income taxes per Mcfe were $0.11 for the three months ended June 30, 2014 and 2013, respectively, and $0.12 and $0.11 for the six months ended June 30, 2014 and 2013, respectively. 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 was $1.09 per Mcfe for the three months ended June 30, 2014 compared to $1.05 for the same period in 2013. For the first six months of 2014, our full cost pool amortization rate was $1.10 per Mcfe compared to $1.07 per Mcfe for the same period in 2013. 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.

Unevaluated costs excluded from amortization were $958 million at June 30, 2014 compared to $957 million at December 31, 2013. The increase in unevaluated costs since December 31, 2013 primarily resulted from our acquisition of acreage in the Sand Wash Basin in the second quarter of 2014 as well as an increase in our wells in progress; slightly offset by the movement of certain New Ventures acreage to evaluated. Unevaluated costs excluded from amortization at June 30, 2014 included $79 million related to our properties in Canada, compared to $72 million at December 31, 2013.

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 June 30,		For the six months ended June 30,	
	2014	2013	2014	2013
	($ in millions, except volumes)			
Revenues – marketing	$ 992	$ 760	$ 2,088	$ 1,360
Revenues – gathering	$ 139	$ 127	$ 273	$ 248
Gas purchases – marketing	$ 976	$ 750	$ 2,061	$ 1,342
Operating costs and expenses	$ 62	$ 64	$ 125	$ 117
Operating income	$ 93	$ 73	$ 175	$ 149
Gas volumes marketed (Bcf)	225	189	441	369
Gas volumes gathered (Bcf)	240	223	473	437

Revenues

Revenues from our marketing activities were up 31% to $992 million for the three months ended June 30, 2014 and were up 54% to $2,088 million for the six months ended June 30, 2014 compared to the same periods in 2013. For the three months ended June 30, 2014, the volumes marketed increased 19% and the price received for volumes marketed increased 9% compared to the same period in 2013. For the six months ended June 30, 2014, the volumes marketed increased 20% and the price received for volumes marketed increased 28% compared to the same period in 2013. 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 97% of the marketed volumes for the three months ended June 30, 2014 and 2013, respectively. For the six months ended June 30, 2014 and 2013, production from our affiliated E&P operated wells accounted for 96% and 96% of the marketed volumes, respectively.

Revenues from our gathering activities were up 9% to $139 million for the three months ended June 30, 2014 and up 10% to $273 million for the six months ended June 30, 2014 compared to the same periods in 2013. The increase in gathering revenues resulted primarily from an 8% increase in gas volumes gathered for the three months ended June 30, 2014 and 8% in the six months ended June 30, 2014, compared to the same period in 2013. A majority of the increase in gathering revenues for the three and six months ended June 30, 2014 resulted from increases in volumes gathered due to our development and growth of our shale properties. Gathering volumes, revenues and expenses for this segment are expected to continue to grow as reserves related to our shale properties are developed and production increases.

Operating Income

Operating income from our Midstream Services segment increased to $93 million for the three months ended June 30, 2014 compared to $73 million for the same period in 2013 and increased to $175 million for the six months ended June 30, 2014 compared to $149 million for the same period in 2013. Operating income was higher due to increases in gas volumes gathered which primarily resulted from our increase in E&P production volumes. The $20 million increase in operating income for the three months ended June 30, 2014 was due to an increase of $12 million in gathering revenues and an increase of $6 million in the margin generated from our gas marketing activities, and a decrease of $2 million in operating costs and expenses. The $26 million increase in operating income for the six months ended June 30, 2014 was due to an increase of $25 million in gathering revenues and an increase of $9 million in the margin generated from our gas marketing activities, which was partially offset by a $8 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 $16 million for the three months ended June 30, 2014 compared to $10 million for the three months ended June 30, 2013. The margin generated from gas marketing activities was $27 million for the six months ended June 30, 2014 compared to $18 million for the six months ended June 30, 2013. Margins are primarily driven by volumes of natural gas marketed and may fluctuate depending on the prices paid for commodities and the ultimate disposition of those commodities. We enter into hedging activities from time to time with respect to our natural gas marketing activities to provide margin protection. We refer you to Item 3, "Quantitative and Qualitative Disclosures about Market Risks" included in this Form 10-Q for additional information.

Interest Expense

Interest expense, net of capitalization, increased to $12 million for the three months ended June 30, 2014, compared to $9 million for the same period in 2013 and increased to $25 million for the six months ended June 30, 2014 compared to $19 million for the same period in 2013. The increase in interest expense, net of capitalization, for the three months ended June 30, 2014 was primarily due to a decrease in capitalized interest for the three months ended June 30, 2014. We capitalized interest of $13 and $17 million for the three months ended June 30, 2014 and 2013, respectively. The decrease in capitalized interest for the three months ending June 30, 2014 compared to the same period in 2013 was primarily due to a reduction in the Company's weighted average interest rate and a decrease in our unevaluated property balance. We capitalized interest of $26 and $33 million for the six month periods ended June 30, 2014 and 2013, respectively.

Gain (Loss) on Derivatives

At June 30, 2014, our basis swaps, certain fixed price swaps, call options and interest rate swaps were not designated for hedge accounting treatment. Changes in the fair value of derivatives that were not designated as cash flow hedges are recorded in gain (loss) on derivatives. For the six months ended June 30, 2014, we recorded a loss on derivatives excluding derivatives, settled of $23 million related to fixed price call options not designated for hedge accounting treatment, a loss on derivatives excluding derivatives, settled of $21 million related to fixed price swaps not designated for hedge accounting, a loss on derivatives excluding derivatives, settled of $13 million related to the basis swaps not designated for hedge accounting treatment, and a loss on derivatives excluding derivatives, settled of $5 million related to interest rate swaps not designated for hedge accounting treatment. Fixed prices swaps that were designated for hedge accounting and settled resulted in a loss of $67 million for the six months ended June 30, 2014 and a gain of $125 million for the six months ended June 30, 2013. Derivatives not designated for hedge accounting that were settled resulted in a loss of $46 million for the six months ended June 30, 2014 and a gain of $1 million for the six months ended June 30, 2013. In general and without consideration of volatility or duration, as 2015 natural gas prices increase from June 30, 2014 levels, the Company will recognize losses in future periods and, likewise, as 2015 natural gas prices decline from June 30, 2014 levels, the Company will recognize gains in future periods on its derivative contracts not accounted for under hedge accounting prior to settlement.

Income Taxes

Our effective tax rate was 40% for the six months ended June 30, 2014 and 2013. For the six months ended June 30, 2014, we recorded an income tax expense of $269 million compared to an income tax expense of $249 million for the same period in 2013.

Stock-Based Compensation Expense

We recognized expense of $4 million and capitalized $4 million for stock-based compensation during the three months ended June 30, 2014 compared to $3 million expense and $3 million capitalized for the comparable period in 2013. We recognized expense of $9 million and capitalized $9 million for stock-based compensation costs recognized during the six month period ended June 30, 2014 compared to $6 million expense and $6 million capitalized for the comparable period in 2013. We refer you to Note 14 in the unaudited condensed consolidated financial statements included in this Form 10-Q for additional discussion of our equity based compensation plans.

Reconciliation of Non-GAAP Measures

We report our financial results in accordance with accounting principles generally accepted in the United States of America ("GAAP"). However, management believes certain non-GAAP performance measures may provide users of this financial information additional meaningful comparisons between current results and the results of our peers and of prior periods. Such non-GAAP performance measures include Adjusted EBITDA, adjusted net income, diluted adjusted earnings per share, and net cash flow (also referred to as net cash provided by operating activities before changes in net assets and liabilities).

Adjusted EBITDA is defined as net income plus interest, income tax expense, non-cash impairment of natural gas and oil properties, (gain) loss on derivatives excluding derivatives, settled, and depreciation, depletion and amortization. Management presents measures concerning Adjusted EBITDA because it is used by many investors as a measure of the ability of a company to service or incur indebtedness and because it is a financial measure commonly used in the energy industry. Adjusted EBITDA should not be considered in isolation or as a substitute for net income, net cash provided by operating activities or other income or cash flow data prepared in accordance with GAAP, or as a measure of the company's profitability or liquidity. Adjusted EBITDA as defined above may not be comparable to similarly titled measures of other companies. Net income is a financial measure calculated and presented in accordance with GAAP that is most directly comparable to Adjusted EBITDA as defined. The table below reconciles Adjusted EBITDA, as defined, with net income.

	For the three months ended June 30,		For the six months ended June 30,	
	2014	2013	2014	2013
	(in millions)			
Net Income	$ 207	$ 246	$ 401	$ 373
Net interest expense	12	9	25	19
Provision for income taxes	140	164	269	249
Depreciation, depletion and amortization expense	230	187	455	366
Add back:				
(Gain) Loss on derivatives excluding derivatives, settled	–	93	62	(63)
Adjusted EBITDA	$ 589	$ 699	$ 1,212	$ 944

Adjusted net income and adjusted diluted earnings per share exclude certain charges or amounts and are measures Management presents because (i) they are consistent with the manner in which the Company's performance is measured relative to the performance of its peers, (ii) these measures are more comparable to earnings estimates provided by securities analysts, and (iii) charges or amounts excluded cannot be reasonably estimated and guidance provided by the Company excludes information regarding these types of items. These adjusted amounts are not a measure of financial performance under GAAP. The table below reconciles adjusted net income and diluted adjusted earnings per share with net income.

	For the three months ended June 30,			
	2014		2013	
	(in millions)	(per diluted share)	(in millions)	(per diluted share)
Net income	$ 207	$ 0.59	$ 246	$ 0.70
Add back:				
(Gain) Loss on derivatives excluding derivatives, settled (net of taxes)	–	–	(56)	(0.16)
Adjusted net income	$ 207	$ 0.59	$ 190	$ 0.54

	For the six months ended June 30,			
	2014		2013	
	(in millions)	(per diluted share)	(in millions)	(per diluted share)
Net income	$ 401	$ 1.14	$ 373	$ 1.06
Add back:				
(Gain) Loss on derivatives excluding derivatives, settled (net of taxes)	37	0.10	(38)	(0.11)
Adjusted net income	$ 438	$ 1.24	$ 335	$ 0.95

Management presents the measure of net cash flow because (i) it is accepted as an indicator of an oil and gas exploration and production company's ability to internally fund exploration and development activities and to service or incur additional debt, (ii) changes in operating assets and liabilities relate to the timing of cash receipts and disbursements which the company may not control and (iii) changes in operating assets and liabilities may not relate to the period in which the operating activities occurred. These adjusted amounts are not a measure of financial performance under GAAP. The table below reconciles net cash flow with the cash flow from operating activities.

	For the six months ended June 30,	
	2014	2013
	(in millions)	
Net cash provided by operating activities	$ 1,194	$ 878
Add back:		
Change in operating assets and liabilities	2	40
Net cash flow	$ 1,196	$ 918

New Accounting Standards

In May 2014, the FASB issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (Topic 606) ("Update 2014-09"), which seeks to provide clarity for recognizing revenue. Topic 606 Revenue from Contracts with Customers will supersede the revenue recognition requirements in Topic 605 Revenue Recognition. Update 2014-09 requires an entity to recognize revenue to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled for those goods or services. Entities may apply the amendments in Update 2014-09 either (a) retrospectively to each prior reporting period presented, and the entity may elect a practical expedient per the Update, or (b) retrospectively with the cumulative effect of initially applying Update 2014-09 recognized at the date of initial application - if an entity elects this transition method it also should provide the additional disclosures in reporting periods. For public entities, Update 2014-09 is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. We are currently evaluating the provisions of Update 2014-09 and assessing the impact, if any, it may have on the Company's consolidated results of operations, financial position or cash flows.

In June 2014, the FASB issued Accounting Standards Update No. 2014-12, Compensation-Stock Compensation (Topic 718): Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could be Achieved After the Requisite Service Period ("Update 2014-12"), which clarifies the accounting treatment of such awards in practice. Update 2014-12 requires that a performance target that affects vesting and that could be achieved after the requisite service period be treated as a performance condition. Entities may apply the amendments in Update 2014-12 either (a) prospectively to all awards granted or modified after the effective date, or (b) retrospectively to all awards with performance targets that are outstanding as of the beginning of the earliest annual period presented in the financial statements and to all new or modified awards thereafter. Update 2014-12 is effective for annual periods and interim periods within those annual periods beginning after December 15, 2015, and early adoption is permitted. We are currently evaluating the provisions of Update 2014-12 and assessing the impact, if any, it may have on the Company's consolidated results of operations, financial position or cash flows.

LIQUIDITY AND CAPITAL RESOURCES

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

For the remainder of 2014, assuming natural gas prices remain at current levels, we intend to draw on a portion of the funds available under our Credit Facility to fund our working capital needs and our planned capital investments (discussed below under "Capital Investments"). We refer you to Note 10 to the unaudited condensed consolidated financial statements included in this Form 10-Q and the section below under "Financing Requirements" for additional discussion of our Credit Facility.

Net cash provided by operating activities increased 36% to $1,194 million for the six months ended June 30, 2014, up from $878 million for the same period in 2013, 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, higher realized gas prices, and an increase in changes in working capital. During the six months ended June 30, 2014, requirements for our capital investments were funded primarily from our cash generated by operating activities, cash and cash equivalents, and net proceeds from borrowings under our Credit Facility. For the six months ended June 30, 2014, cash generated from our operating activities funded 95% of our cash requirements for capital investments compared to 75% for the six months ended June 30, 2013.

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 2014. The credit status of the financial institutions participating in our Credit Facility could adversely impact our ability to borrow funds under the Credit Facility. Although 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, including regional basis differentials. Natural gas and oil prices are subject to wide fluctuations and are driven by market supply and demand factors that 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 $1.3 billion for the six months ended June 30, 2014 compared to $1.2 billion for the comparable period in 2013. Our E&P segment investments were $1.2 billion and $1.1 billion for the six months ended June 30, 2014 and 2013 respectively. Our E&P segment capitalized internal costs of $157 million for the six months ended June 30, 2014 compared to $121 million for the comparable period in 2013. These internal costs were directly related to acquisition, exploration and development activities and are included as part of the cost of natural gas and oil properties.

Our capital investments for 2014 are planned to be approximately $2.4 billion, consisting of $2.1 billion for E&P, $0.1 billion for Midstream Services and $0.2 billion for corporate and other purposes. Of the approximate $2.1 billion for E&P, we expect to allocate approximately $900 million to our Fayetteville Shale assets and approximately $700 million to our Marcellus Shale assets. Our planned level of capital investments in 2014 is expected to allow us to continue our progress in the Fayetteville Shale and Marcellus Shale programs and explore and develop other existing natural gas and oil properties and generate new drilling prospects. Our remaining 2014 capital investment program is expected to be funded through cash flow from operations and borrowings under our revolving credit facility. The planned capital program for 2014 is flexible and can be modified. We will reevaluate our proposed investments as needed to take into account prevailing market conditions and we could change our planned investments.

Financing Requirements

Our total debt outstanding was $1.8 billion at June 30, 2014 compared to $2.0 billion at December 31, 2013. On December 16, 2013, the Company entered into a new Credit Agreement ("Credit Facility"), which exchanged our previous revolving credit facility. Under the Credit Facility, we have a borrowing capacity of $2 billion. The Credit Facility has a maturity date in December 2018 and options for two one-year extensions with participating lender approval. The amount available under the Credit Facility may be increased by $500 million upon the Company's agreement with its participating lenders.

The interest rate on our Credit Facility is calculated based upon our public debt rating and is currently 137.5 basis points over LIBOR. Our publicly traded notes are rated BBB by Standard and Poor's, our senior unsecured debt rating by Fitch Ratings is BBB-, 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 that impose certain restrictions on us. Under the Credit Facility, we must keep our total debt at or below 60% of our total adjusted book capital. This financial covenant with respect to capitalization percentages excludes the effects of any full cost ceiling impairments (after December 31, 2011), certain non-cash hedging activities and our pension and other postretirement liabilities. Therefore, under our Credit Facility provision, our capital structure as of June 30, 2014, was 26% debt and 74% equity. We were in compliance with all of the covenants of our Credit Facility as of June 30, 2014. 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.

At June 30, 2014, our capital structure consisted of 31% debt and 69% equity (exclusive of cash and cash equivalents) and $20 million in cash and cash equivalents, compared to 35% debt and 65% equity and $23 million in cash and cash equivalents at December 31, 2013. Equity at June 30, 2014 included $9 million related to our pension and other postretirement liabilities partially offset by an accumulated other comprehensive gain of $1 million related to our hedging activities. The amount recorded in equity for our hedging activities is based on current market values for our hedges at June 30, 2014 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 29, 2014, we had NYMEX commodity price hedges in place on 233 Bcf of our remaining targeted 2014 natural gas production and 240 Bcf of our expected 2015 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 2013 Annual Report on Form 10-K.

Contingent Liabilities and 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 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 $45 million Canadian dollars. The promissory notes secure the Company's capital expenditure obligations under the licenses and are returnable to the Company to the extent the Company performs such obligations. If the Company fails to fully perform, the Minister of Finance may retain a portion of the applicable promissory notes in an amount equal to any deficiency. The Company commenced its Canada exploration program in 2010 and, as of June 30, 2014 has invested $43 million Canadian dollars, or $41 million US dollars, in New Brunswick towards the Company's commitment. In December 2012, the Company received two one-year extensions to our exploration license agreements, the second of which will expire on March 16, 2015. No liability has been recognized in connection with the promissory notes due to the Company's investments in New Brunswick as of June 30, 2014 and its future investment plans.

The Company entered into new and amended natural gas transportation and gathering arrangements with third party pipelines, during the second quarter of 2014, in support of the Company's production in the Marcellus Shale. As of June 30, 2014, the Company's obligations for demand and similar charges under the firm transportation agreements and gathering agreements totaled approximately $3.8 billion and the Company has guarantee obligations of up to $100 million of that amount.

Substantially all of our employees are covered by defined pension and postretirement benefit plans. As of June 30, 2014, the Company has contributed $6 million to the pension plan, and expects to contribute an additional $6 million to the pension plan in 2014. At June 30, 2014, we recognized a liability of $17 million as a result of the underfunded status of our pension and other postretirement benefit plans compared to a liability of $16 million at December 31, 2013.

We are subject to litigation, claims and proceedings (including with respect to environmental matters) that arise in the ordinary course of business. Management believes, individually or in aggregate, such litigation, claims and proceedings will not have a material adverse impact on our financial position, results of operations, or cash flows, but these matters are subject to inherent uncertainties and management's view may change in the future. If an unfavorable final outcome were to occur, there exists the possibility of a material impact on our financial position, results of operations or cash flows for the period in which the effect becomes reasonably estimable. We accrue for such items when a liability is both probable and the amount can be reasonably estimated. For further information regarding commitments and contingencies, we refer you to Note 11 in the unaudited condensed consolidated financial statements included in this Form 10-Q.

Working Capital

We had negative working capital of $224 million at June 30, 2014 and negative working capital of $44 million at December 31, 2013. Current assets increased by $18 million during the six months ended June 30, 2014 primarily due to a $49 million increase in accounts receivable, partially offset by a $31 million decrease in current hedging asset. Current liabilities increased by $198 million during the six months ended June 30, 2014 primarily as a result of a $180 million increase in accounts payable and an approximate $43 million increase in other current liabilities and derivative liabilities, offset slightly by a $24 million decrease in current deferred income taxes. 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. The Board of Directors has approved our use of financial products for the reduction of interest rate risks. 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 six months ended June 30, 2014. See "Commodities Risk" below for discussion of credit risk associated with commodities trading.

Interest Rate Risk

At June 30, 2014, we had approximately $1.8 billion of total debt with a weighted average interest rate of 5.08%. Our revolving credit facility has a floating interest rate (1.50% at June 30, 2014). At June 30, 2014, we had borrowings outstanding of $171 million under our Credit Facility.

Interest rate swaps may be used to adjust interest rate exposures when deemed appropriate. At June 30, 2014, the Company had a net derivative liability position of $3 million related to interest rate swaps. A 10% increase or decrease in interest rates would not result in a material increase or decrease in the aggregate fair value of outstanding interest rate swap agreements. For a summary of the Company's open interest rate derivative positions, see Note 7-Derivative Instruments in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

Commodities Risk

We use over-the-counter natural gas and crude oil swap agreements and options to hedge sales of our production 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, 2014, the net fair value of our financial instruments related to natural gas production was a $35 million liability.

	Volume (Bcf)	Weighted Average Fixed Price Swaps ($/MMBtu)	Weighted Average Floor Price ($/MMBtu)	Weighted Average Ceiling Price ($/MMBtu)	Weighted Average Basis Differential ($/MMBtu)	Fair value at June 30, 2014 ($ in millions)
Natural Gas (Bcf):						
Fixed Price Swaps:						
2014	233	$ 4.35	$ –	$ –	$ –	$ (24)
2015	240	$ 4.40	$ –	$ –	$ –	$ 44
Basis Swaps:						
2014	17	$ –	$ –	$ –	$ 0.29	$ 16
2015	15	$ –	$ –	$ –	$ 0.61	$ (15)
2016	4	$ –	$ –	$ –	$ 0.72	$ (3)
Fixed Price Call Options:						
2015	200	$ –	$ –	$ 5.09	$ –	$ (28)
2016	120	$ –	$ –	$ 5.00	$ –	$ (25)

At June 30, 2014, our basis swaps, certain fixed price swaps, call options and interest rate swaps were not designated for hedge accounting treatment. Changes in the fair value of derivatives that are not designated as cash flow hedges are recorded in gain (loss) on derivatives. For the six months ended June 30, 2014, we recorded a loss on derivatives excluding derivatives, settled of $23 million related to fixed price call options not designated for hedge accounting treatment, a loss on derivatives excluding derivatives, settled of $21 million related to fixed price swaps not designated for hedge accounting, a loss on derivatives excluding derivatives, settled of $13 million related to the basis swaps not designated for hedge accounting treatment, a loss on derivatives excluding derivatives, settled of $5 million related to interest rate swaps not designated for hedge accounting treatment and a loss of $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 Rules 13a-15(e) and 15d 15(e) under the Securities Exchange Act of 1934, as amended. Our disclosure controls and procedures are the controls and other procedures that we have designed to ensure that we record, process, summarize and report 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, 2014 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the quarter ended June 30, 2014 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.

We are 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.

Tovah Energy

In February 2009, SEPCO was added as a defendant in a case then styled Tovah Energy, LLC and Toby Berry-Helfand v. David Michael Grimes, et, al., pending in the 273rd District Court in Shelby County, Texas. By the time of trial in December 2010, Ms. Berry-Helfand (the only remaining plaintiff) alleged that, in 2005, she 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, she alleged 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 2005 and February 2006. She also sought disgorgement of SEPCO's profits. A former associate of the plaintiff intervened in the matter claiming to have helped develop the prospect years earlier.

The jury found in favor of the plaintiff and the intervenor with respect to all of the statutory and common law claims and awarded $11 million in compensatory damages but no special, punitive or other damages. Separately, the jury determined that SEPCO's profits for purposes of disgorgement, if ordered as a remedy, were $382 million. (Disgorgement of profits is an equitable remedy determined by the judge, and it is within the judge's discretion to award none, some or all of unlawfully obtained profits.) In August 2011, a judgment was entered pursuant to which the plaintiff and the intervenor were entitled to recover approximately $11 million in actual damages and approximately $24 million in disgorgement as well as prejudgment interest and attorneys' fees, which currently are estimated to be up to $9 million, and all costs of court of the plaintiff and intervenor.

Both sides appealed and in July 2013, the Texas Court of Appeals in Tyler ordered that (1) the judgment awarding the plaintiff and the intervenor $24 million as disgorgement of illicit gains be reversed and judgment rendered that they take nothing, (2) the award of $11 million for actual damages, insofar as it is based on the jury's findings of breach of fiduciary duty, fraud, breach of contract, and theft of trade secret be reversed and judgment rendered that the plaintiff and the intervenor take nothing under those theories of recovery, (3) the award of $11 million to the plaintiff and the intervenor as damages for misappropriation of trade secret be affirmed, (4) the case be remanded to the trial court for a determination and award of attorney's fees for SEPCO as the prevailing party under the Texas Theft Liability Act, and (5) in all other respects, the judgment is affirmed. All parties petitioned for rehearing. The Court of Appeals denied rehearing in November 2013.

SEPCO filed a petition for review in the Supreme Court of Texas in February 2014. The plaintiff and the intervenor filed cross-petition for review in April 2014, but conditioned their filing on the court's granting SEPCO's petition for review; i.e., if the court denies SEPCO's petition for review, then the plaintiff and the intervenor are not seeking further review of the court of appeals' judgment. Based on the Company's understanding and judgment of the facts and merits of this case, including appellate matters, and after considering the advice of counsel, the Company has determined that, although reasonably possible, a materially adverse final outcome to this action is not probable. As such, the Company has not accrued any amounts with respect to this action. If the Supreme Court declines to hear the case or affirms all aspects of the court of appeals' judgment, then SEPCO would owe the $11 million in damages, plus interest and attorneys fees, offset by any award of attorneys' fees for its prevailing on the theft count. The Company's assessment may change in the future due to occurrence of certain events, such as the result of the petition or petitions for review at the Supreme Court of Texas, and such a 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.

Other

The Company is subject to various litigation, claims and proceedings that have arisen in the ordinary course of business, such as for alleged breaches of contract, miscalculation of royalties and pollution, contamination or nuisance. Management believes that such litigation, claims and proceedings, individually or in aggregate and after taking into account insurance, are not likely to have a material adverse impact on our financial position, results of operations or cash flows. Many of these matters are in early stages, so the allegations and the damage theories have not been fully developed, and all subject to inherent uncertainties; therefore, 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 the Company's financial position, results of operations or cash flows for the period in which the effect becomes reasonably estimable. The Company accrues 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 2013 Annual Report on Form 10-K.

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

Not applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES.

Not applicable.

ITEM 4. MINE SAFETY DISCLOSURES.

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

ITEM 5. OTHER INFORMATION.

Not applicable.

ITEM 6. EXHIBITS.

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

Signatures

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

SOUTHWESTERN ENERGY COMPANY
Registrant

Dated: July 31, 2014

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

General Permit Route Sheet

Facility Name	Scotland 2 Discharge		
Permit Number Outfall 001	ARG 670804	AFIN NO.*	71-00467
Stream Segment: 4E	Receiving Stream:	unnamed trib to Scotland Branch	
Assigned HUC 11010014	Activity	Initials	Date Complete/Entered
Outfall 002: stream segment 3F HUC 11110203 Sect.	Application Logged/Assign Tracking Number/Place in red folder with appropriate route sheet and filing folders (1-day)	KB	N/A
Engineer	Completeness and Technical Review/Enter permit information into Database (3-days)	JT	8-6-14
AA (Max of 5 business days)	AFIN request (1-day)	JB	8/6
	Enter AFIN and other information into PDS and NPDES database prior to requesting invoice (same day)	JB	8/6
	Complete Invoice Request Form and submit Invoice Request (same day)	JB	8/6
	Prepare Authorization letter and attach appropriate permit, forms (1-day)	JB	8/6
Engineer	Review/organize folder for scanning (1-day)	JT	8-6-14
Engineer Supervisor	Review all the documents/permits/ perform technical review for the proposed project. (1-day)		8-7-14
Assistant Chief	Review the documents and sign the authorization letter or the permit. (1-day)		8/8/14
AA	Enter Into PDS: Permit Status/Effective Date. Input effective date in access database. (1-day)	JB	8/11
Sect.	Mail original to applicant. Scan complete folder and place in appropriate E-drive folders. Update Zylab. Be sure to include this permit in weekly report, due every Tuesday by 2:00 P.M.	KB	8-12

REMARKS: ______________________