SOUTHWESTERN ENERGY CO
Form 10-Q
April 21, 2016
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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 March 31, 2016

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: 001-08246
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.)

10000 Energy Drive

Spring, Texas	77389
(Address of principal executive offices)	(Zip Code)

(832) 796-1000
(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 April 19, 2016
Common Stock, Par Value $0.01	392,666,629

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SOUTHWESTERN ENERGY COMPANY

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FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2016

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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

All statements, other than historical fact or present financial information, may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). 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 Quarterly Report on Form 10-Q identified by words such as “anticipate,” “intend,” “plan,” “project,” “estimate,” “continue,” “potential,” “should,” “could,” “may,” “will,” “
“guidance,” “outlook,” “effort,” “expect,” “believe,” “predict,” “budget,” “projection,” “goal,” “forecast,” “target” or similar w

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:

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- the timing and extent of changes in market conditions and prices for natural gas, oil and natural gas liquids ("NGLs") (including regional basis differentials);
- our ability to fund our planned capital investments;
- a change in our credit rating;
- the extent to which lower commodity prices impact our ability to service or refinance our existing debt;
- the impact of volatility in the financial markets or other global economic factors;
- difficulties in appropriately allocating capital and resources among our strategic opportunities;
- the timing and extent of our success in discovering, developing, producing and estimating reserves;
- our ability to maintain leases that may expire if production is not established or profitability maintained;
- our ability to realize the expected benefits from recent acquisitions;
- difficulties in integrating our operations as a result of any significant acquisitions;
- our ability to transport our production to the most favorable markets or at all;
- the impact of government regulation, including the ability to obtain and maintain permits, any increase in severance or similar taxes, and legislation relating to hydraulic fracturing, climate and over-the-counter derivatives;
- 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;
- 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").

Should one or more of the risks or uncertainties described above or elsewhere in this Quarterly Report 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.

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PART I – FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS.

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

	For the three months ended March 31,	
	2016	2015
	(in millions, except share/per share amounts)	
Operating Revenues:		
Gas sales	$ 315	$ 625
Oil sales	11	17
NGL sales	17	18
Marketing	198	225
Gas gathering	38	48
	579	933
Operating Costs and Expenses:		
Marketing purchases	196	222
Operating expenses	165	155
General and administrative expenses	54	68
Restructuring charges	64	–
Depreciation, depletion and amortization	143	293
Impairment of natural gas and oil properties	1,034	–
Taxes, other than income taxes	23	30
	1,679	768
Operating Income (Loss)	(1,100)	165
Interest Expense:		
Interest on debt	53	50
Other interest charges	2	49
Interest capitalized	(41)	(48)
	14	51
Other Loss, Net	(3)	(1)
Gain (Loss) on Derivatives	(14)	14
Income (Loss) Before Income Taxes	(1,131)	127
Provision for Income Taxes:		
Deferred	1	49

Net Income (Loss)	$ (1,132)	$ 78
Mandatory convertible preferred stock dividend	27	25
Participating securities - mandatory convertible preferred stock	–	7
Net Income (Loss) Attributable to Common Stock	$ (1,159)	$ 46
Earnings (Loss) Per Common Share:		
Basic	$ (3.03)	$ 0.12
Diluted	$ (3.03)	$ 0.12
Weighted Average Common Shares Outstanding:		
Basic	382,870,847	375,444,030
Diluted	382,870,847	375,578,054

The accompanying notes are an integral part of these

unaudited condensed consolidated financial statements.

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

	For the three months ended March 31,	
	2016	2015
	(in millions)	
Net income (loss)	$ (1,132)	$ 78
Change in derivatives:		
Settlements (1)	–	(25)
Change in fair value of derivative instruments (2)	–	17
Total change in derivatives	–	(8)
Change in value of pension and other postretirement liabilities:		
Amortization of prior service cost and net loss included in net periodic pension cost (3)	1	–
Change in currency translation adjustment	3	(6)
Comprehensive income (loss)	$ (1,128)	$ 64

(1) Net of ($17) million in taxes for the three months ended March 31, 2015.
(2) Net of $7 million in taxes for the three months ended March 31, 2015.
(3) Net of $1 million in taxes for the three months ended March 31, 2016.

The accompanying notes are an integral part of these

unaudited condensed consolidated financial statements.

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

	March 31, 2016	December 31, 2015
ASSETS	(in millions)	
Current assets:		
Cash and cash equivalents	$ 1,597	$ 15
Accounts receivable, net	224	327
Derivative assets	35	3
Other current assets	28	48
Total current assets	1,884	393
Natural gas and oil properties, using the full cost method, including $3,505 million as of March 31, 2016 and $3,727 million as of December 31, 2015 excluded from amortization	22,610	22,478
Gathering systems	1,281	1,280
Other	602	606
Less: Accumulated depreciation, depletion and amortization	(18,002)	(16,821)
Total property and equipment, net	6,491	7,543
Other long-term assets	143	150
TOTAL ASSETS	$ 8,518	$ 8,086
LIABILITIES AND EQUITY		
Current liabilities:		
Short-term debt	$ 1	$ 1
Accounts payable	346	513
Taxes payable	52	64
Interest payable	32	75
Dividends payable	27	27
Derivative liabilities	8	3
Other current liabilities	12	24
Total current liabilities	478	707
Long-term debt	6,442	4,704
Deferred income taxes	2	–
Pension and other postretirement liabilities	50	50
Other long-term liabilities	398	343
Total long-term liabilities	6,892	5,097
Commitments and contingencies (Note 11)		
Equity:		
Common stock, $0.01 par value; 1,250,000,000 shares authorized; issued 389,673,678 shares as of March 31, 2016 (does not include 3,024,737 shares declared as a stock dividend on March 16, 2016 and issued on April 15, 2016) and 390,138,549 as of December 31, 2015	4	4
Preferred stock, $0.01 par value, 10,000,000 shares authorized, 6.25% Series B Mandatory Convertible, $1,000 per share liquidation preference, 1,725,000 shares issued and outstanding as of March 31, 2016 and December 31, 2015, conversion in January 2018	–	–
Additional paid-in capital	3,403	3,409
Accumulated deficit	(2,214)	(1,082)

Accumulated other comprehensive loss	(44)	(48)
Common stock in treasury, 31,269 shares as of March 31, 2016 and 47,149 shares as of December 31, 2015, respectively	(1)	(1)
Total equity	1,148	2,282
TOTAL LIABILITIES AND EQUITY	$ 8,518	$ 8,086

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

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

	For the three months ended March 31,	
	2016	2015
	(in millions)	
Cash Flows From Operating Activities		
Net income (loss)	$ (1,132)	$ 78
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	143	293
Impairment of natural gas and oil properties	1,034	–
Amortization of debt issuance costs	2	46
Deferred income taxes	1	49
Loss on derivatives, net of settlement	21	21
Stock-based compensation	9	6
Restructuring charges	42	–
Other	5	–
Change in assets and liabilities:		
Accounts receivable	103	38
Accounts payable	(124)	(35)
Taxes payable	(12)	(20)
Interest payable	(11)	(1)
Other assets and liabilities	11	66
Net cash provided by operating activities	92	541
Cash Flows From Investing Activities		
Capital investments	(196)	(508)
Acquisitions	–	(591)
Proceeds from sale of property and equipment	–	1
Other	–	3
Net cash used in investing activities	(196)	(1,095)
Cash Flows From Financing Activities		
Payments on short-term debt	–	(4,500)
Payments on revolving credit facility	(864)	(830)
Borrowings under revolving credit facility	2,600	1,330
Payments on commercial paper	(242)	–
Borrowings under commercial paper	242	–
Change in bank drafts outstanding	(19)	(7)
Proceeds from issuance of long-term debt	–	2,200
Debt issuance costs	–	(17)
Proceeds from issuance of common stock	–	669

Proceeds from issuance of mandatory convertible preferred stock	–	1,673
Preferred stock dividend	(27)	–
Other	(4)	–
Net cash provided by financing activities	1,686	518
Increase (decrease) in cash and cash equivalents	1,582	(36)
Cash and cash equivalents at beginning of year	15	53
Cash and cash equivalents at end of period	$ 1,597	$ 17

The accompanying notes are an integral part of these

unaudited condensed consolidated financial statements.

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

	Common Stock		Preferred Stock					
	Shares Issued	Amount	Shares	Additional Paid-In Capital	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Common Stock in Treasury	Total
	(in millions, except share amounts)							
Balance at December 31, 2015	390,138,549	$ 4	1,725,000	$ 3,409	$ (1,082)	$ (48)	$ (1)	$ 2,282
Comprehensive loss:								
Net loss	–	–	–	–	(1,132)	–	–	(1,132)
Other comprehensive income	–	–	–	–	–	4	–	4
Total comprehensive loss	–	–	–	–	–	–	–	(1,128)
Stock-based compensation	–	–	–	26	–	–	–	26
Preferred stock dividend	–	–	–	(27)	–	–	–	(27)
Issuance of restricted stock	84,165	–	–	–	–	–	–	–
Cancellation of restricted stock	(24,333)	–	–	–	–	–	–	–
Tax withholding – stock compensation	(524,703)	–	–	(5)	–	–	–	(5)
Balance at March 31, 2016	389,673,678	$ 4	1,725,000	$ 3,403	$ (2,214)	$ (44)	$ (1)	$ 1,148

The accompanying notes are an integral part of these

unaudited condensed consolidated financial statements.

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SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(1) BASIS OF PRESENTATION

Southwestern Energy Company (including its subsidiaries, collectively "Southwestern" or the "Company") is an independent energy company engaged in natural gas and oil exploration, development and production ("E&P"). The Company's current operations are principally focused within the United States on the development of unconventional reservoirs located in Pennsylvania, West Virginia and Arkansas.

The Company's operations in northeast Pennsylvania are primarily focused on the unconventional natural gas reservoir known as the Marcellus Shale (herein referred to as "Northeast Appalachia"), its operations in West Virginia and southwest Pennsylvania are focused on the Marcellus Shale, the Utica and the Upper Devonian unconventional natural gas and oil reservoirs (herein referred to as "Southwest Appalachia") and its operations in Arkansas are primarily focused on an unconventional natural gas reservoir known as the Fayetteville Shale. Collectively, the Company's properties located in Pennsylvania and West Virginia are herein referred to as the "Appalachian Basin." The Company also actively seeks to find and develop new natural gas and oil plays with significant exploration and exploitation potential, which it refers to as "New Ventures," and has exploration and production activities ongoing in Colorado and Louisiana, along with other areas in which it is currently exploring for new development opportunities. The Company also has drilling rigs in Pennsylvania, West Virginia and Arkansas, as well as in other operating areas, and provides oilfield products and services, principally serving its exploration and production operations. Southwestern's natural gas gathering and marketing ("Midstream Services") activities primarily support the Company's E&P activities in Arkansas, Pennsylvania, Louisiana and West Virginia.

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. 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 for the year ended December 31, 2015 ("2015 Annual Report").

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 2015 Annual Report.

Certain reclassifications have been made to the prior year financial statements to conform to the 2016 presentation. The effects of the reclassifications were not material to the Company's unaudited condensed consolidated financial statements.

(2) CASH AND CASH EQUIVALENTS

The following table presents a summary of Cash and cash equivalents as of March 31, 2016 and December 31, 2015:

	March 31, 2016	December 31, 2015
	(in millions)	
Cash	$ 57	$ 15
Marketable securities	1,540	–
Total cash and cash equivalents	$ 1,597	$ 15

On March 30, 2016, the Company borrowed $1.55 billion on its revolving credit facility with the proceeds invested in marketable securities. The $1.55 billion borrowing was repaid on April 1, 2016. For related discussion see Note 10 to the unaudited condensed consolidated financial statements included in this Quarterly Report.

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(3) REDUCTION IN WORKFORCE

In January 2016, the Company announced a 40% workforce reduction of approximately 1,100 employees as a result of lower anticipated drilling activity. This reduction was substantially complete as of March 31, 2016. The following table presents a summary of the restructuring charges for the three months ended March 31, 2016:

	For the three months ended March 31, 2016 (in millions)	
Severance (including payroll taxes)	$	42
Stock-based compensation		18
Benefits		3
Outplacement services, other		1
Total restructuring charges (1)	$	64

(1) Total restructuring charges were $61 million and $3 million for the Company's E&P and Midstream segments, respectively.

As of March 31, 2016, the Company recorded a liability of $24 million for severance payments (including payroll taxes) which is reflected in accounts payable on the condensed consolidated balance sheets. A substantial portion of this liability will be paid in April 2016.

(4) ACQUISITIONS AND DIVESTITURES

In May 2015, the Company sold conventional oil and gas assets located in East Texas and the Arkoma Basin for approximately $211 million. The net book value of these assets was primarily in the full cost pool and was held in the E&P segment as of the closing date. The proceeds from the transaction were used to reduce the Company's debt. Approximately $205 million of the proceeds received were recorded as a reduction of the capitalized costs of the Company's natural gas and oil properties in the United States pursuant to the full cost method of accounting.

In April 2015, the Company sold its gathering assets located in Bradford and Lycoming counties in northeast Pennsylvania to Howard Midstream Energy Partners, LLC for an adjusted sales price of approximately $489 million. The net book value of these assets was $206 million and was held in the Midstream segment as of the closing date. A gain on sale of $283 million was recognized and is included in gain on sale of assets, net on the unaudited condensed consolidated statement of operations. The assets include approximately 100 miles of natural gas gathering pipelines, with nearly 600 million cubic feet per day of capacity. The proceeds from the transaction were used to substantially repay borrowings under the Company's $500 million term loan facility that would have matured in December 2016.

In January 2015, the Company completed an acquisition of certain natural gas and oil assets including approximately 46,700 net acres in northeast Pennsylvania from WPX Energy, Inc. for an adjusted purchase price of $270 million (the "WPX Property Acquisition"). This acreage was producing approximately 50 million net cubic feet of gas per day from 63 operated horizontal wells as of December 2014. As part of this transaction, the Company assumed firm transportation capacity of 260 million cubic feet of gas per day predominantly on the Millennium pipeline. The firm transport is being amortized over 19 years. As of March 31, 2016 and December 31, 2015 the Company has amortized $10 million and $8 million, respectively. This transaction was funded with the revolving credit facility and was accounted for as a business combination.

In January 2015, the Company completed an acquisition in which the Company's subsidiary acquired certain natural gas and oil assets from Statoil ASA covering approximately 30,000 acres in West Virginia and southwest Pennsylvania comprising approximately 20% of Statoil's interests in that acreage for $357 million, (the "Statoil Property Acquisition"). All of these assets are also assets in which the Company has acquired interests under the Chesapeake Property Acquisition, as defined below. This transaction was funded with the revolving credit facility and was accounted for as a business combination. The Company allocated approximately $357 million of the purchase price to natural gas and oil properties, based on the respective fair values of the assets acquired.

In December 2014, the Company completed an acquisition of certain oil and gas assets from Chesapeake Energy Corporation covering approximately 413,000 net acres in West Virginia and southwest Pennsylvania targeting natural gas, natural gas liquids ("NGLs") and crude oil contained in the Upper Devonian, Marcellus and Utica Shales for approximately $5.0 billion (the "Chesapeake Property Acquisition"). The transaction was temporarily financed using a $4.5 billion 364-day senior unsecured bridge term loan credit facility and a $500 million two-year unsecured term loan. The Company repaid all principal and interest outstanding on the $4.5 billion bridge facility in January 2015 after permanent financing was finalized and, as a result, expensed $47 million of short-term unamortized debt issuance costs related to the bridge facility in January 2015 recognized in other interest charges on the unaudited condensed consolidated statement of operations. The term loan facility was repaid in full in April 2015 with proceeds from the divestiture of the Company’s northeastern Pennsylvania gathering assets and borrowings under the revolving credit facility.

(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 properties. 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 are subject to a ceiling test that limits such pooled costs, net of applicable deferred taxes, to the aggregate of the present value of future net revenues attributable to proved natural gas, oil and NGL reserves discounted at 10% (standardized measure) 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, oil and NGL prices may subsequently increase the ceiling. Companies using the full cost method are required to use the average quoted price from the first day of each month from the previous 12 months, including the impact of derivatives qualifying as cash flow hedges, to calculate the ceiling value of their reserves.

Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $2.40 per MMBtu, West Texas Intermediate oil of $42.77 per barrel and NGLs of $5.76 per barrel, adjusted for market differentials, the Company’s net book value of its United States natural gas and oil properties exceeded the ceiling by $641 million (net of tax) at March 31, 2016 and resulted in a non-cash ceiling test impairment. The Company had no hedge positions accounted for as cash flow hedges as of March 31, 2016. Decreases in market prices as well as changes in production rates, levels of reserves, evaluation of costs excluded from amortization, future development costs and production costs could result in future ceiling test impairments.

Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $3.88 per MMBtu, West Texas Intermediate oil of $79.21 per barrel and NGLs of $16.38 per barrel, adjusted for market differentials, the net book value of the Company’s United States natural gas and oil properties did not exceed the ceiling amount and did not result in a ceiling test impairment at March 31, 2015. Cash flow hedges of natural gas production in place increased the ceiling amount by approximately $45 million as of March 31, 2015. In the second, third and fourth quarters of 2015, the Company’s net book value of its United States natural gas and oil properties exceeded the ceiling by approximately $944 million (net of tax) at June 30, 2015, $1,746 million (net of tax) at September 30, 2015 and $1,586 million (net of tax) at December 31, 2015, resulting in non-cash ceiling test impairments in each quarter.

(6) EARNINGS PER SHARE

Basic earnings per common share is computed by dividing net income (loss) attributable to common stock by the weighted average number of common shares outstanding during the reportable period. The diluted earnings per share calculation adds to the weighted average number of common shares outstanding: the incremental shares that would have been outstanding assuming the exercise of dilutive stock options, the vesting of unvested restricted shares of common stock and performance units and the assumed conversion of mandatory convertible preferred stock. An antidilutive impact is an increase in earnings per share or a reduction in net loss per share resulting from the conversion, exercise, or contingent issuance of certain securities.

In January 2015, the Company completed concurrent underwritten public offerings of 30,000,000 shares of its common stock and 34,500,000 depositary shares (both share counts include shares issued as a result of the underwriters exercising their options to purchase additional shares). The common stock offering was priced at $23.00 per share. Net proceeds, after underwriting discount and expenses, from the common stock offering were approximately $669 million. Net proceeds, after underwriting discount and expenses, from the depositary share offering were approximately $1.7 billion. Each depositary share represents a 1/20th interest in a share of the Company's mandatory convertible preferred stock, with a liquidation preference of $1,000 per share (equivalent to a $50 liquidation preference per depositary share). The proceeds from the offerings were used to partially repay borrowings under the Company's $4.5 billion 364-day bridge facility with the remaining balance of the bridge facility fully repaid with proceeds from the Company's January 2015 public offering of $2.2 billion in long-term senior notes.

The mandatory convertible preferred stock entitles the holder to a proportional fractional interest in the rights and preferences of the convertible preferred stock, including conversion, dividend, liquidation and voting rights. Unless converted earlier at the option of the holders, on or around January 15, 2018 each share of convertible preferred stock will automatically convert into between 37.0028 and 43.4782 shares of the Company's common stock (and, correspondingly, each depositary share will convert into between 1.85014 and 2.17391 shares of the Company's common stock), subject

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to customary anti-dilution adjustments, depending on the volume-weighted average price of the Company's common stock over a 20 trading day averaging period immediately prior to that date.

The mandatory convertible preferred stock has the non-forfeitable right to participate on an as-converted basis at the conversion rate then in effect in any common stock dividends declared and as such, is considered a participating security. Accordingly, it is included in the computation of basic and diluted earnings per share, pursuant to the two-class method. In the calculation of basic earnings per share attributable to common shareholders, participating securities are allocated earnings based on actual dividend distributions received plus a proportionate share of undistributed net income attributable to common shareholders, if any, after recognizing distributed earnings. The Company's participating securities do not participate in undistributed net losses because they are not contractually obligated to do so.

On March 16, 2016, the Company declared its quarterly dividend, payable to holders of the mandatory convertible preferred stock, and announced that it would pay the dividend in common stock, in lieu of cash, to the extent permitted by the certificate of designations for the Series B preferred stock. The Company issued 3,024,737 shares of common stock on April 15, 2016 in payment of the dividend.

The following table presents the computation of earnings per share for the three months ended March 31, 2016 and 2015:

	For the three months ended March 31,	
	2016	2015
	(in millions, except share/per share amounts)	
Net income (loss)	$ (1,132)	$ 78
Mandatory convertible preferred stock dividend	27	25
Net income (loss) attributable to shareholders	(1,159)	53
Participating securities - mandatory convertible preferred stock	–	7
Net income (loss) attributable to common stock	$ (1,159)	$ 46
Number of common shares:		
Weighted average outstanding	382,870,847	375,444,030
Issued upon assumed exercise of outstanding stock options (1)	–	–
Effect of issuance of non-vested restricted common stock (2)	–	133,634
Effect of issuance of non-vested performance units (3)	–	390

Effect of issuance of mandatory convertible preferred stock (4)	–	–
Effect of declaration of preferred stock dividends (5)	–	–
Weighted average and potential dilutive outstanding	382,870,847	375,578,054
Earnings (loss) per common share:		
Basic	$ ($3.03)	$ 0.12
Diluted	$ ($3.03)	$ 0.12

(1) Due to the net loss for the three months ended March 31, 2016, the unvested stock options were not recognized in diluted earnings per share calculations as they would be antidilutive. Options for 5,732,521 shares and 3,704,089 shares were excluded from the calculation of diluted shares for the three months ended March 31, 2016 and 2015, respectively, because they would have had an antidilutive effect.

(2) Due to the net loss for the three months ended March 31, 2016, the unvested share-based payments were not recognized in diluted earnings per share calculations as they would be antidilutive. The calculation excluded 5,779,820 shares and 1,916,645 shares of restricted stock for the three months ended March 31, 2016 and 2015, respectively, because they would have had an antidilutive effect.

(3) For the three months ended March 31, 2016, 297,297 shares of performance units were excluded from the calculation of diluted earnings per share as they would be antidilutive.

(4) For the three months ended March 31, 2016 and 2015, 74,999,895 and 58,333,252, respectively, of weighted average common shares issuable upon the assumed conversion of the mandatory convertible preferred stock were excluded from the diluted earnings per share calculation as they would be antidilutive.

(5) Due to the net loss for the three months ended March 31, 2016, 3,024,737 shares of common stock declared as preferred stock dividends were excluded from the diluted earnings per share calculations as they would have had an antidilutive effect.

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(7) DERIVATIVES AND RISK MANAGEMENT

The Company is exposed to volatility in market prices and basis differentials for natural gas, oil and NGLs which impacts the predictability of its cash flows related to the sale of those commodities. These risks are managed by the Company's use of certain derivative financial instruments. As of March 31, 2016, the Company's derivative financial instruments consisted of fixed price swaps, sold call options, purchased put options and interest rate swaps. The Company also had basis swaps and sold call options as of December 31, 2015. The basis swaps settled in the first quarter of 2016. 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.
Sold call options	The Company sells call options in exchange for a premium. If the market price exceeds the strike price of the call option at the time of settlement, the Company pays the counterparty such excess on sold call options. If the market price settles below the call's strike price, no payment is due from either party.
Purchased put options	The Company purchases put options from the counterparty by payment of a cash premium. If the market price is lower than the put's strike price at the time of settlement, the Company receives from the counterparty such difference on purchased put options. If the market price settles above the put's strike price, no payment is due from either party.
Basis swaps	Arrangements that guarantee a price differential for natural gas from a specified delivery point. The Company receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract.
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.

The Company utilizes counterparties for its derivative instruments that it believes are credit-worthy at the time the transactions are entered into and the Company closely monitors the credit ratings of these counterparties. Additionally, the Company performs both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. However, the events in the financial markets in recent years demonstrate there can be no assurance that a counterparty will be able to meet its obligations to the Company.

The following table provides information about the Company's financial instruments that are sensitive to changes in commodity prices and that are used to protect the Company's exposure. None of the financial instruments below are designated for hedge accounting treatment. The table presents the notional amount in Bcf, the weighted average contract prices and the fair value by expected maturity dates as of March 31, 2016.

		Weighted Average Price per MMBtu			
	Volume (Bcf)	Swaps	Purchased Puts	Sold Calls	Fair value at March 31, 2016 ($ in millions)
Natural Gas:					
Fixed Price Swaps:					
2016	64	$ 2.48	$ –	$ –	$ 20
Purchased Put Options:					
2016	43	$ –	$ 2.35	$ –	$ 15
Sold Call Options:					
2016	90	$ –	$ –	$ 5.00	$ –
2017	86	$ –	$ –	$ 3.25	$ (16)
2018	63	$ –	$ –	$ 3.50	$ (12)
2019	52	$ –	$ –	$ 3.50	$ (13)
2020	32	$ –	$ –	$ 3.75	$ (9)

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The balance sheet classification of the assets related to derivative financial instruments (none of which are designated for hedge accounting) are summarized below as of March 31, 2016 and December 31, 2015:

	Derivative Assets Balance Sheet Classification	Fair Value March 31, 2016	December 31, 2015
		(in millions)	
Basis swaps	Derivative assets	$ –	$ 3
Fixed price swaps	Derivative assets	20	–
Purchased put options	Derivative assets	15	–
Total derivative assets		$ 35	$ 3

	Derivative Liabilities Balance Sheet Classification	Fair Value March 31, 2016	December 31, 2015
		(in millions)	
Sold call options	Derivative liabilities	$ 5	$ –
Interest rate swaps	Derivative liabilities	3	3
Sold call options	Other long-term liabilities	45	–
Interest rate swaps	Other long-term liabilities	5	2
Total derivative liabilities		$ 58	$ 5

At March 31, 2016, the net fair value of the Company's financial instruments related to natural gas was a $15 million liability. The net fair value of the Company's interest rate swaps was an $8 million liability at March 31, 2016.

Derivative Contracts not Designated for Hedge Accounting

As of March 31, 2016, the Company did not have any positions designated for hedge accounting treatment. Gains and losses on derivatives that are not designated for hedge accounting treatment, or that do not meet hedge accounting requirements, are recorded as a component of gain (loss) on derivatives on the condensed consolidated statements of operations. Accordingly, the gain (loss) on derivatives component of the statements of operations reflects the gains and losses on both settled and unsettled derivatives. The Company calculates gains and losses on settled derivatives as the summation of gains and losses on positions which have settled within the reporting period. Only the settled gains and losses are included in the Company's realized commodity price calculations.

The Company is a party to interest rate swaps that were entered into to mitigate the Company's exposure to volatility in interest rates. The interest rate swaps have 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 unaudited condensed consolidated statements of operations.

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The following tables summarize the before tax effect of fixed price swaps, basis swaps, sold call options, purchased put options and interest rate swaps not designated for hedge accounting on the unaudited condensed consolidated statements of operations for the three months ended March 31, 2016 and 2015:

Derivative Instrument	Consolidated Statement of Operations Classification of Gain (Loss) on Derivatives, Unsettled	Gain (Loss) on Derivatives, Unsettled Recognized in Earnings For the three months ended March 31, 2016	2015
		(in millions)	
Basis swaps	Gain (Loss) on Derivatives	$ (3)	$ (8)
Sold call options	Gain (Loss) on Derivatives	(50)	8
Purchased put options	Gain (Loss) on Derivatives	15	–
Fixed price swaps	Gain (Loss) on Derivatives	20	(18)
Interest rate swaps	Gain (Loss) on Derivatives	(3)	(3)
Total loss on unsettled derivatives		$ (21)	$ (21)

Derivative Instrument	Consolidated Statement of Operations Classification of Gain (Loss) on Derivatives, Settled (1)	Gain (Loss) on Derivatives, Settled (1) Recognized in Earnings For the three months ended March 31, 2016	2015
		(in millions)	
Basis swaps	Gain (Loss) on Derivatives	$ 4	$ (6)
Fixed price swaps	Gain (Loss) on Derivatives	4	42
Interest rate swaps	Gain (Loss) on Derivatives	(1)	(1)
Total gain on settled derivatives (2)		$ 7	$ 35
Total gain (loss) on derivatives		$ (14)	$ 14

(1) The Company calculates gain (loss) on derivatives, settled, as the summation of gains and losses on positions that have settled within the period.
(2) These amounts are included, along with gas sales revenues, in the calculation of the Company's realized natural gas price.

Derivative Contracts Designated for Hedge Accounting

All derivatives are recognized in the balance sheet as either an asset or liability and are measured at fair value other than transactions for which normal purchase/normal sale is applied. Certain criteria must be satisfied in order for derivative financial instruments to be designated for hedge accounting. Accounting guidance for qualifying hedges allows an unsettled derivative's unrealized gains and losses to be recorded either in earnings or as a component of other comprehensive income until settled. In the period of settlement, the Company recognizes the gains and losses from these qualifying hedges in operating revenues. In 2015, the Company had certain fixed price swaps that were designated for hedge accounting. For the three months ended March 31, 2015, the Company reported a gain in other comprehensive income of $24 million (pre-tax) related to the effective portion of our unsettled fixed price swaps. The ineffective portion of those fixed price swaps was recognized in earnings and had an inconsequential impact to the unaudited condensed consolidated statement of operations for the three ended March 31, 2015. During the first quarter of 2015, a gain of $42 million (pre-tax) on settled fixed price swaps was transferred from other comprehensive income into gas sales revenues in the consolidated statements of operations. As of March 31, 2016, the Company did not have any positions designated for hedge accounting treatment.

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(8) RECLASSIFICATIONS FROM ACCUMULATED OTHER COMPREHENSIVE INCOME

The following tables detail the components of accumulated other comprehensive income (loss) and the related tax effects for the three months ended March 31, 2016:

	For the three months ended March 31, 2016		
	Pension and Other Postretirement	Foreign Currency (1)	Total
	(in millions)		
Beginning balance at December 31, 2015	$ (25)	$ (23)	$ (48)
Other comprehensive income before reclassifications	–	3	3
Amounts reclassified from other comprehensive income (loss) (2)	1	–	1
Net current-period other comprehensive loss	1	3	4
Ending balance at March 31, 2016	$ (24)	$ (20)	$ (44)

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

Details about Accumulated Other Comprehensive Income	Affected Line Item in the Consolidated Statement of Operations	Amount Reclassified from Accumulated Other Comprehensive Income For the three months ended March 31, 2016 (in millions)
Pension and other postretirement		

Amortization of prior service cost and net loss (1)	General and administrative expenses	$ 2
	Provision for income taxes	1
Total reclassifications for the period	Net loss	$ 1

(1) See Note 12 for additional details regarding the Company's retirement and employee benefit plans.

(9) FAIR VALUE MEASUREMENTS

The carrying amounts and estimated fair values of the Company's financial instruments as of March 31, 2016 and December 31, 2015 were as follows:

	March 31, 2016		December 31, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Cash and cash equivalents	$ 1,597	$ 1,597	$ 15	$ 15
Credit facility	1,852	1,852	116	116
Term loan facility	748	748	747	747
Senior notes	3,843	2,729	3,842	2,651
Derivative instruments, net	(23)	(23)	(2)	(2)

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 value of the Company's publicly traded debt as determined based on the yield of the Company's senior notes.

The carrying values of the borrowings under the Company's unsecured revolving credit and term loan facilities approximate 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.

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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.

The fair value hierarchy 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 fixed price swaps (Level 2) are estimated using third-party discounted cash flow calculations using the NYMEX futures index. The Company utilized discounted cash flow models for valuing its interest rate derivatives (Level 2). The net derivative values attributable to the Company's interest rate derivative contracts as of March 31, 2016 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 sold call options and purchased put options (Level 3) 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 (Level 3) are estimated using third-party 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 the most significant inputs on a monthly basis. An increase (decrease) in volatility would result in an increase (decrease) in fair value measurement, respectively. However, such changes would not have a significant impact.

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

	March 31, 2016			
	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
Fixed price swap assets	$ –	$ 20	$ –	$ 20
Purchased put option assets	–	–	15	15
Interest rate swap liabilities	–	(8)	–	(8)
Sold call option liabilities	–	–	(50)	(50)
Total	$ –	$ 12	$ (35)	$ (23)

	December 31, 2015			
	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
Basis swap assets	$ –	$ –	$ 3	$ 3
Interest rate swap liabilities	–	(5)	–	(5)
Total	$ –	$ (5)	$ 3	$ (2)

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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 months ended March 31, 2016 and 2015. 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 reasonable assumptions a marketplace participant would have used as of March 31, 2016 and 2015.

	For the three months ended March 31,	
	2016	2015
	(in millions)	
Balance at beginning of period	$ 3	$ (8)
Total gains (losses):		
Included in earnings	(34)	(6)
Purchases, issuances, and settlements:		
Settlements	(4)	6
Transfers into/out of Level 3	–	–
Balance at end of period	$ (35)	$ (8)
Change in losses included in earnings relating to derivatives still held as of March 31	$ (38)	$ –

(10) DEBT

The components of debt as of March 31, 2016 and December 31, 2015 consisted of the following:

	March 31, 2016 (in millions)			
	Debt Instrument	Unamortized Issuance Cost	Unamortized Debt Discount	Total
Short-term debt:				
7.15% Senior Notes due May 2018	$ 1	$ –	$ –	$ 1
Total short-term debt	$ 1	$ –	$ –	$ 1
Long-term debt:				
Variable rate (4.154% at March 31, 2016) credit facility, expires December 2018	1,852	–	–	1,852
Variable rate (2.025% at March 31, 2016) term loan facility, due November 2018	750	(2)	–	748
7.35% Senior Notes due October 2017	15	–	–	15
7.125% Senior Notes due October 2017	25	–	–	25
3.3% Senior Notes due January 2018	350	(2)	–	348
7.5% Senior Notes due February 2018	600	(2)	–	598
7.15% Senior Notes due May 2018	26	–	–	26
4.05% Senior Notes due January 2020	850	(5)	–	845
4.10% Senior Notes due March 2022	1,000	(5)	(1)	994
4.95% Senior Notes due January 2025	1,000	(7)	(2)	991
Total long-term debt	$ 6,468	$ (23)	$ (3)	$ 6,442
Total debt	$ 6,469	$ (23)	$ (3)	$ 6,443

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	December 31, 2015 (in millions)			
	Debt Instrument	Unamortized Issuance Cost	Unamortized Debt Discount	Total
Short-term debt:				
7.15% Senior Notes due May 2018	$ 1	$ –	$ –	$ 1
Total short-term debt	$ 1	$ –	$ –	$ 1
Long-term debt:				
Variable rate (1.886% at December 31, 2015) credit facility, expires December 2018	116	–	–	116
Variable rate (1.775% at December 31, 2015) term loan facility, due November 2018	750	(3)	–	747
7.35% Senior Notes due October 2017	15	–	–	15
7.125% Senior Notes due October 2017	25	–	–	25
3.3% Senior Notes due January 2018	350	(2)	–	348
7.5% Senior Notes due February 2018	600	(2)	–	598
7.15% Senior Notes due May 2018	26	–	–	26
4.05% Senior Notes due January 2020	850	(5)	(1)	844
4.10% Senior Notes due March 2022	1,000	(5)	(1)	994
4.95% Senior Notes due January 2025	1,000	(7)	(2)	991
Total long-term debt	$ 4,732	$ (24)	$ (4)	$ 4,704
Total debt	$ 4,733	$ (24)	$ (4)	$ 4,705

Credit Facility

The Company's revolving credit facility entered into in December 2013, provides a borrowing capacity of up to $2.0 billion, reduced for any outstanding letters of credit, and matures in December 2018, with options for two one-year extensions with participating lender approval. The Company had $148 million of letters of credit outstanding as of March 31, 2016. The borrowing capacity available under the revolving credit facility may be increased by $500 million upon the Company's agreement with its participating lenders. The interest rate on the revolving credit facility is calculated based upon the Company's public debt ratings from Standard & Poor's ("S&P") and Moody's Investors Service ("Moody's") and was 200.0 basis points over LIBOR as of March 31, 2016. Since the adjustment ceiling per the terms of the revolving credit facility is 200.0 basis points, the interest rate sensitivity on the Company's revolving credit facility currently correlates directly to changes in LIBOR. On March 30, 2016, the Company borrowed $1.55 billion on the revolving credit facility. On April 1, 2016, the Company repaid the $1.55 billion borrowing in full. As of March 31, 2016, the Company had $1.9 billion drawn on the credit facility and $0.1 billion in letters of credit.

The revolving credit facility and the term loan facility are unsecured and are not guaranteed by any subsidiaries of the Company. The revolving credit facility and the term loan facility contain covenants imposing certain restrictions on the Company, including a financial covenant under which Southwestern 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, certain hedging activities, unamortized issuance cost, unamortized debt discount and the Company's pension and other postretirement liabilities. As of March 31, 2016, the Company's adjusted capital structure was 45% debt and 55% equity and was in compliance with the covenants of its revolving credit facility, term loan facility and other debt agreements.

Term Facility

In November 2015, the Company entered into a $750 million unsecured three-year term loan credit agreement with various tenders that was utilized to repay borrowings under the revolving credit facility. The interest rate on the term loan facility is determined based upon the Company's public debt ratings from S&P and Moody's and was 162.5 basis points over the London Interbank Offered Rate ("LIBOR") as of March 31, 2016. The term loan facility requires prepayment under certain circumstances from the net cash proceeds of sales of equity or certain assets and borrowings outside the ordinary course of business.

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Public Offering of Senior Notes

In January 2015, the Company completed a public offering of $350 million aggregate principal amount of its 3.30% senior notes due 2018 (the “2018 Notes”), $850 million aggregate principal amount of its 4.05% senior notes due 2020 (the “2020 Notes”) and $1 billion aggregate principal amount of its 4.95% senior notes due 2025 (the “2025 Notes” together with the 2018 and 2020 Notes, the “Notes”), with net proceeds from the offering totaling approximately $2.2 billion after underwriting discounts and offering expenses. The proceeds from this offering were used to repay the remaining principal and interest outstanding under the Company’s $4.5 billion 364-day bridge term loan facility, which was first reduced with proceeds from the Company’s concurrent underwritten public offerings of common and preferred stock, and were also used to repay a portion of amounts outstanding under the Company’s revolving credit facility. As a result of this repayment, the Company expensed $47 million of short-term unamortized debt issuance costs related to the bridge facility in January 2015 recognized in other interest charges on the unaudited condensed consolidated statement of operations for the three months ended March 31, 2015. The Notes were sold to the public at a price of 99.949% of their face value for the 2018 Notes, 99.897% of their face value for the 2020 Notes and 99.782% of their face value for the 2025 Notes. The interest rates on the Notes is determined based upon the Company’s public debt ratings from S&P and Moody’s. Downgrades from either rating agency increase interest costs by 25.0 basis points per downgrade level on the following semi-annual bond interest payment. In February 2016, S&P and Moody’s downgraded the Company’s credit ratings, increasing the interest rates on these notes by 125.0 basis points effective July 2016. As a result of the downgrade, the Company’s interest expense for 2016 will increase $14 million. The first higher interest rate coupon payment to bondholders will be paid in January 2017.

Commercial Paper

In April 2015, the Company entered into a commercial paper program which allowed it to issue up to $2.0 billion in commercial paper provided that borrowings from its commercial paper program combined with outstanding borrowings under its revolving credit facility, not exceed $2.0 billion. The commercial paper issuance had terms of up to 397 days and carried interest at rates agreed upon at the time of each issuance. As of March 31, 2016, the Company had no outstanding issuances under its commercial paper program and had no plans of utilizing the commercial paper market for the remainder of 2016.

(11) COMMITMENTS AND CONTINGENCIES

Operating Commitments and Contingencies

As of March 31, 2016, the Company’s contractual obligations for demand and similar charges under firm transportation and gathering agreements to guarantee access capacity on natural gas and liquids pipelines and gathering systems totaled approximately $8.6 billion, $3.3 billion of which related to access capacity on future pipeline and gathering infrastructure projects that still require the granting of regulatory approvals and additional construction efforts. The Company also had guarantee obligations of up to $861 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 results of operations of the Company.

Litigation

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 the Company's 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 are 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.

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Tovah Energy

In February 2009, one of the Company's subsidiaries 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 the Company's subsidiary with proprietary data regarding two prospects in the James Lime formation pursuant to a confidentiality agreement and that the Company's subsidiary 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 the Company's subsidiary between February 2005 and February 2006. She also sought disgorgement of the Company's subsidiary'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 the Company's subsidiary'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 Tyler Court of Appeals 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 is 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 secrets is affirmed, (4) the case be remanded to the trial court for a determination and award of attorney's fees for the Company's subsidiary 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 Tyler Court of Appeals denied rehearing in November 2013.

The Company's subsidiary filed a petition for review in the Supreme Court of Texas in February 2014. The plaintiff and the intervenor filed a cross-petition for review in April 2014, but conditioned their filing on the court's granting the Company's subsidiary's petition for review; i.e., if the court denies the Company's subsidiary's petition for review, then the plaintiff and the intervenor are not seeking further review of the court of appeals' judgment. The Supreme Court granted the parties' petitions and heard oral argument on the case in October 2015 but has not yet issued a decision. 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 affirms all aspects of the court of appeals' judgment, then the Company's subsidiary 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 depending on the Supreme Court's decision, 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.

Arkansas Royalty Litigation

Certain of the Company's subsidiaries are defendants in three cases, two filed in Arkansas state court in 2010 and 2013 and one in federal court in 2014, on behalf of putative classes of royalty owners on some of the Company's leases located in Arkansas. The chief complaint in all three cases is that one of the Company's subsidiaries underpaid the royalty owners by, among other things, deducting from royalty payments costs for gathering, transportation, and compression of natural gas in excess of what is permitted by the relevant leases. In September and October 2014 the judges in the two Arkansas state actions entered orders certifying classes of royalty owners who are citizens of Arkansas. The Company's subsidiaries have appealed those orders. Oral argument has not yet been set in either case.

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On November 17, 2015, the court in the federal case denied the plaintiff's motion to certify a class of royalty owners not included in either of the two state cases. On April 11, 2016, the court certified a broader class that includes Arkansas residents and citizens. The plaintiff in the federal case presented two alternative damages theories. Under one theory, plaintiffs have asserted that obligations to affiliates are not "incurred" and therefore the exploration and production subsidiary was not entitled to deduct any post-production costs; the federal court has granted partial summary judgment for the Company's subsidiaries on this theory. Under another theory, plaintiffs assert that the gathering and treating rates it deducted from royalty payments exceeded the affiliates' actual costs or otherwise were not reasonable. The plaintiffs have not disclosed a specific damage calculation for any putative class, but based on the class representative's disclosure regarding the calculation of claimed damages, class-wide damages could exceed $100 million. Although trial previously was set for March 15, 2016, following transfer to a different judge and the certification of the class described above, that trial date has been vacated and no new date set.

In addition, in September 2015 three cases were filed in Arkansas state court on behalf of a total of 248 individually named plaintiffs. Each case asserts complaints that are in substance virtually identical to the above-described case. The Company and its subsidiaries have removed two of the cases to federal court, and those cases have been assigned to the court in which the above-described federal case is pending. All three cases have been stayed.

Management believes that, in all of the above cases, the deductions from royalty payments as calculated are permitted and intends to defend the cases vigorously. The Company's assessment may change in the future due to the occurrence of certain events, such as adverse judgments, 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.

Indemnifications

The Company provides certain indemnifications in relation to dispositions of assets. These indemnifications typically relate to disputes, litigation or tax matters existing at the date of disposition. No liability has been recognized in connection with these indemnifications.

(12) PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

The Company has defined pension and postretirement benefit plans which cover substantially all of the Company's employees. Net periodic pension costs include the following components for the three months ended March 31, 2016 and 2015:

	Pension Benefits For the three months ended March 31,	
	2016	2015
	(in millions)	
Service cost	$ 4	$ 4
Interest cost	2	1
Expected return on plan assets	(2)	(2)
Amortization of prior service cost	–	–
Amortization of net loss	–	1
Net periodic benefit cost	$ 4	$ 4

The Company's postretirement benefit plan had a net periodic benefit cost of $1 million as of the three months ended March 31, 2016 and 2015. For the three months ended March 31, 2016, the Company has contributed $3 million to the pension and postretirement benefit plans. In January 2016, the Company initiated a reduction in workforce that was effectively completed by the end of the first quarter. As a result of the workforce reduction, the Company continues to evaluate its pension and other postretirement benefit funding requirements and will disclose its funding plans once reasonably determined.

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 31,269 shares at March 31, 2016 compared to 47,149 shares at December 31, 2015.

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(13) STOCK-BASED COMPENSATION

The Company recognized the following amounts in employee stock-based compensation costs for the three months ended March 31, 2016 and 2015:

	For the three months ended March 31,	
	2016	2015
	(in millions)	
Stock-based compensation cost – expensed (1)	$ 23	$ 6
Stock-based compensation cost – capitalized	$ 3	$ 5

(1) Includes $18 million related to the reduction in workforce that occurred in the first quarter of 2016.

In January 2016, the Company announced a 40% workforce reduction that was substantially concluded by the end of March 2016. Affected employees were offered a severance package that included, if applicable, amendments to outstanding equity awards that modified forfeiture provisions on separation from the Company. As a result, unvested stock-based equity awards became fully vested at the time of separation. These shares were revalued and recognized immediately as a component of restructuring charges on the Company's condensed consolidated statements of operations.

As of March 31, 2016, there was $86 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.

Stock Options

The following table summarizes stock option activity for the three months ended March 31, 2016 and provides information for options outstanding and options exercisable as of March 31, 2016:

	Number of Options	Weighted Average

	(in thousands)	Exercise Price (per share)
Outstanding at December 31, 2015	5,623	$ 24.57
Granted	156	8.60
Exercised	–	–
Forfeited or expired	(10)	30.29
Outstanding at March 31, 2016	5,769	24.13
Exercisable at March 31, 2016	2,567	$ 36.12

Restricted Stock

The following table summarizes restricted stock activity for the three months ended March 31, 2016 and provides information for unvested shares as of March 31, 2016:

	Number of Shares (in thousands)	Weighted Average Fair Value (per share)
Unvested shares at December 31, 2015	7,222	$ 13.24
Granted	77	8.35
Vested (1)	(1,947)	8.32
Forfeited	(24)	12.11
Unvested shares at March 31, 2016	5,328	$ 13.24

(1) Includes 1,887,160 shares related to the reduction in workforce that occurred in the first quarter of 2016.

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Equity-Classified Performance Units

The following table summarizes performance unit activity to be paid out in Company stock for the three months ended March 31, 2016 and provides information for unvested units as of March 31, 2016. The performance units awarded in 2013 and 2014 include a market condition based on Relative Total Shareholder Return (“TSR”) and a performance condition based on the Company's Present Value Index (“PVI”), collectively the “Performance Measures.” 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 economic analysis for each investment opportunity based upon the expected present value added for each dollar to be invested and amortized to compensation expense on a straight line basis over the vesting period of the award. The performance units awarded in 2015 are based exclusively on TSR. The grant date fair value is calculated using the Performance Measures and the closing price of the Company’s common stock at the grant date.

	Number of Units (1) (in thousands)	Weighted Average Fair Value (per share)
Unvested units at December 31, 2015	407	$ 36.65
Granted (2)	1,061	8.31
Vested (3)	(5)	8.08
Forfeited	(38)	8.08
Unvested units at March 31, 2016	1,425	$ 14.47

(1) These amounts reflect the number of performance units granted in thousands. The actual payout of shares may range from a minimum of zero shares to a maximum of two shares contingent upon the actual performance against the Performance Measures.
(2) Excludes 441,450 units in excess of individual award limits subject to shareholder approval of the amended 2013 Incentive Plan at the annual meeting on May 17, 2016.
(3) Includes 5,168 units related to the reduction in workforce that occurred in the first quarter of 2016.

Liability-Classified Performance Units

Prior to 2013, certain employees were provided performance units vesting equally over three years, payable in cash. The payout of these units was based on certain metrics, such as total shareholder return and reserve replacement efficiency, compared to a predetermined group of peer companies and Company goals. At the end of each performance period, the value of the vested performance units, if any, would be paid in cash. In the first quarter of 2016, the Company completed the final payout under these performance unit agreements.

(14) SEGMENT INFORMATION

The Company's reportable business segments have been identified based on the differences in products or services provided. Revenues for the E&P segment are derived from the production and sale of natural gas and liquids. The Midstream Services segment generates revenue through the marketing of both Company and third-party produced natural gas and liquids 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 2015 Annual Report. 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, gain (loss) on derivatives, and other loss. The "Other" column includes items not related to the Company's reportable segments including real estate and corporate items.

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	Exploration and Production (in millions)		Midstream Services		Other		Total
Three months ended March 31, 2016:							
Revenues from external customers	$343		$ 236		$ –		$579
Intersegment revenues	(7)		385		–		378
Depreciation, depletion and amortization expense	127		16		–		143
Impairment of natural gas and oil properties	1,034		–		–		1,034
Operating income (loss)	(1,160)	(1)	60	(2)	–		(1,100)
Interest expense (3)	14		–		–		14
Other loss, net	(2)		(1)		–		(3)
Loss on derivatives	(13)		(1)		–		(14)
Provision for income taxes (3)	1		–		–		1
Assets	5,538		1,220		1,760	(4)	8,518
Capital investments (5)	120		2		–		122
Three months ended March 31, 2015:							
Revenues from external customers	$660		$ 273		$ –		$933
Intersegment revenues	(5)		665		1		661
Depreciation, depletion and amortization expense	278		15		–		293
Operating income (loss)	78		88		(1)		165
Interest expense (3)	45		7		(1)		51
Other loss, net	(1)		–		–		(1)
Gain (loss) on derivatives	15		–		(1)		14
Provision for income taxes (3)	18		31		–		49
Assets	13,703		1,616		242	(4)	15,561
Capital investments (5)	1,030		138		3		1,171

(1) Operating income (loss) for the E&P segment includes $61 million related to restructuring charges.
(2) Operating income (loss) for the Midstream segment includes $3 million related to restructuring charges.
(3) Interest expense and the provision for income taxes by segment are an allocation of corporate amounts as they are incurred at the corporate level.
(4) Other assets represent corporate assets not allocated to segments and assets for non-reportable segments. At March 31, 2016, other assets includes $1.55 billion in marketable securities, which were sold on April 1, 2016 to repay revolver debt. See Note 2 to the unaudited condensed consolidated financial statements included in this Quarterly Report for additional discussion.
(5) Capital investments includes a $78 million decrease and an immaterial increase for the three months ended March 31, 2016 and 2015, respectively, relating to the change in accrued expenditures between periods. E&P capital for the three month period ended March 31, 2015 includes approximately $534 million related to the WPX Property and Statoil Property Acquisitions. Midstream capital for the three months ended March 31, 2015 includes

approximately $119 million associated with the intangible asset related to the firm transportation acquired through the WPX Property Acquisition.

Included in intersegment revenues of the Midstream Services segment are $319 million and $576 million for the three months ended March 31, 2016 and 2015, respectively for marketing of the Company's E&P sales. Corporate assets include cash and cash equivalents, furniture and fixtures and other costs. Corporate general and administrative costs, depreciation expense and taxes other than income are allocated to the segments. Capital investments within the E&P segment include $1 million for the three months ended March 31, 2016 and 2015, related to the Company's activities in Canada. The Company's E&P segment assets included $53 million and $71 million at March 31, 2016 and 2015, respectively, related to the Company's activities in Canada.

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(15) INCOME TAXES

The Company's effective tax rate was approximately 0% for the three months ended March 31, 2016, primarily as a result of the recognition of a valuation allowance. A valuation allowance for deferred tax assets, including net operating losses, is recognized when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized. To assess that likelihood, the Company uses estimates and judgment regarding future taxable income, and considers the tax consequences in the jurisdiction where such taxable income is generated, to determine whether a valuation allowance is required. Such evidence can include current financial position, results of operations, both actual and forecasted, the reversal of deferred tax liabilities, and tax planning strategies as well as the current and forecasted business economics of the oil and gas industry.

Due to the material write-downs of the carrying value of oil and natural gas properties and operating results, the Company is in a net deferred tax asset position. The Company believes it is more likely than not that these deferred tax assets will not be realized and recorded a $431 million tax expense for the increase in our valuation allowance. Management assesses the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit the use of deferred tax assets. A significant piece of objective negative evidence evaluated is the projected cumulative loss incurred over the three-year period ending December 31, 2016. Such objective negative evidence limits the ability to consider other subjective positive evidence, such as projections for future growth. The amount of the deferred tax asset considered realizable, however, could be adjusted if estimates of future taxable income are reduced or increased or if objective negative evidence in the form of cumulative losses is no longer present and additional weight is given to subjective evidence such as future expected growth.

(16) NEW ACCOUNTING PRONOUNCEMENTS

New Accounting Standards Implemented

In April 2015, the FASB issued Accounting Standards Update No. 2015-03, Interest-Imputation of Interest (Subtopic 835-30) ("Update 2015-03"), in an effort to simplify presentation of debt issuance costs. Update 2015-03 required that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs was not affected by the amendments in this Update. Entities were required to apply the amendments in Update 2015-03 on a retrospective basis, with the balance sheet of each individual period presented adjusted to reflect the period-specific effects of applying the new guidance. In August 2015, the FASB issued Accounting Standards Update No. 2015-15, Interest-Imputation of Interest (Subtopic 835-30) ("Update 2015-15"), which addressed the presentation or subsequent measurement of debt issuance costs related to line-of-credit arrangements, given the absence of authoritative guidance within Update 2015-03 for debt issuance costs related to line-of-credit arrangements. For public entities, Update 2015-03 and Update 2015-15 were effective for annual reporting periods beginning after December 15, 2015, including interim periods within that reporting period. The Company adopted this update in the first quarter of 2016 resulting in an immaterial impact on its unaudited condensed consolidated results of operations, financial position and cash flows. At December 31, 2015, the Company had $24 million in unamortized debt expense that was classified as a long-term asset. As of March 31, 2016, long-term debt included a contra liability of $23 million for unamortized debt expense previously recognized as a long-term asset.

In May 2015, the FASB issued Accounting Standards Update No. 2015-07, Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (Or Its Equivalent) (“Update 2015-07”), which amends ASC 820, Fair Value Measurement. The standard removes the requirement to categorize within the fair value hierarchy investments for which fair value is measured using the net asset value per share practical expedient and removes certain related disclosure requirements. The amendments in Update 2015-07 are effective for reporting periods beginning after December 15, 2015, with early adoption permitted. The Company adopted this update in the first quarter of 2016 resulting in no impact on its unaudited condensed consolidated results of operations, financial position and cash flows.

In September 2015, the FASB issued Accounting Standards Update No. 2015-16, Business Combinations (Topic 805) (“Update 2015-16”), which seeks to reduce the complexity of amounts recognized in a business combination. The amendments in Update 2015-16 require that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. The amendments in Update 2015-16 require that the acquirer record, in the same period’s financial statements, the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. The amendments in Update 2015-16 require an entity to present separately on the face of the income statement or disclose in the notes the portion of the amount recorded in current-period earnings by line item that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date. The amendments in Update 2015-

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16 were effective for fiscal years beginning after December 15, 2015, including interim periods within those fiscal years. The Company adopted this update in the first quarter of 2016 resulting in no impact on its unaudited condensed consolidated results of operations, financial position and cash flows.

In November 2014, the FASB issued Accounting Standards Update No. 2014-16, Derivatives and Hedging – Determining Whether the Host Contract in a Hybrid Financial Instrument Issued in the Form of a Share Is More Akin to Debt or to Equity (Subtopic 815-15) ("Update 2014-16"), addresses diversity in practice related to the determination of whether derivative features embedded in hybrid instruments issued in the form of a share should be bifurcated and accounted for separately. For public entities, Update 2014-16 was effective for annual reporting periods beginning after December 15, 2015 including interim periods within that reporting period. The Company adopted this update in the first quarter of 2016 resulting in no impact on its unaudited condensed consolidated results of operations, financial position and cash flows.

New Accounting Standards Not Yet Implemented

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 requirement as 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 to those goods or services. Entities may apply the amendments in Update 2014-09 either (a) retrospectively to each 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. In August 2015, the FASB issued Accounting Standards Update No. 2015-14, Revenue from Contracts with Customers (Topic 606)("Update 2015-14"). Deferral of the Effective Date, which finalizes proposed ASU No. 2015-240 of the same name and responds to stakeholders' request to defer the effective date of the guidance in ASU No. 2014-09. In March 2016, the FASB issued Accounting Standards Update No. 2016-08, Revenue from Contracts with Customers (Topic 606) – Principal versus Agent Considerations (Reporting Revenue Gross versus Net)("Updated 2016-08"), which finalized proposed ASU No. 2015-290 of the same name and clarifies the implementation guidance on principal versus agent considerations. For public entities, Update 2014-09, Update 2015-14, and Update 2016-08 are effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. The Company is currently evaluating the provisions of Update 2014-09, Update 2015-14 and Update 2016-08 and assessing the impact, if any, they may have on its consolidated results of operations, financial position or cash flows.

In July 2015, the FASB issued Accounting Standards Update No. 2015-11, Inventory (Topic 330) ("Update 2015-11"), which seeks to simplify the measurement of inventory. Update 2015-11 requires that an entity should measure inventory at the lower of cost and net realizable value, where net realizable value is the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. For public entities, the amendments in Update 2015-11 are effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years, with early adoption permitted. The Company is currently evaluating the provisions of Update 2015-11 and assessing the impact, if any, it may have on its consolidated results of operations, financial position or cash flows.

In February 2016, the FASB issued Accounting Standards Update No. 2016-02, Leases (Topic 842) (“Update 2016-02”), which seeks to increase transparency and comparability among organizations by, among other things, recognizing lease assets and lease liabilities on the balance sheet for leases classified as operating leases under previous GAAP and disclosing key information about leasing arrangements. For public entities, Update 2016-02 becomes effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, with early adoption permitted. The Company is currently evaluating the provisions of Update 2016-02 and assessing the impact, if any, it may have on its consolidated results of operations, financial position or cash flows.

In March 2016, the FASB issued Accounting Standards Update No. 2016-09, Compensation - Stock Compensation (Topic 718) (“Update 2016-09”), which seeks to simplify accounting for share-based payment transactions including income tax consequences, classification of awards as either equity or liabilities, and the classification on the statement of cash flows. For public entities, Update 2016-09 becomes effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years, with early adoption permitted. The Company is currently evaluating the provisions of Update 2016-09 and assessing the impact, if any, it may have on its consolidated results of operations, financial position or cash flows.

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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 2015 Annual Report and analyzes the changes in the results of operations between the three months ended March 31, 2016 and 2015. For definitions of commonly used natural gas and oil terms used in this Quarterly Report, please refer to the "Glossary of Certain Industry Terms" provided in our 2015 Annual Report.

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 Quarterly Report, in Item 1A, "Risk Factors" in Part I and elsewhere in our 2015 Annual Report, and Item 1A, "Risk Factors" in Part II in this Quarterly Report and any other quarterly report on 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 Quarterly Report.

OVERVIEW

Background

Southwestern Energy Company (including its subsidiaries, collectively, "we", "our", "us" or "Southwestern") is an independent energy company engaged in natural gas and oil exploration, development and production, which we refer to as "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, development and production of natural gas and oil. Our current operations are principally focused on the development of unconventional natural gas reservoirs located in Pennsylvania, West Virginia and Arkansas. Our operations in northeast Pennsylvania, which we refer to as "Northeast Appalachia" are primarily focused on the unconventional natural gas reservoir known as the Marcellus Shale. Our operations in West Virginia and southwest Pennsylvania, which we refer to as "Southwest Appalachia," are focused on the Marcellus Shale, the Utica and the Upper Devonian unconventional natural gas and oil reservoirs. Collectively, we refer to our properties located in Pennsylvania and West Virginia as the "Appalachian Basin." Our operations in Arkansas are primarily focused on an unconventional natural gas reservoir known as the Fayetteville Shale. We also actively seek to find and develop new natural gas and oil plays with significant exploration and exploitation potential, which we refer to as "New Ventures." Under our New Ventures operations, we have exploration and production activities ongoing in Colorado and Louisiana, along with other areas in which we are currently exploring for new development opportunities. We operate drilling rigs and provide oilfield products and services, principally serving our exploration and production operations, though the level of these services in 2016 will depend on our capital investing for the year. Our natural gas gathering and marketing activities primarily support our E&P activities in Arkansas, Pennsylvania, Louisiana and West Virginia.

We are focused on providing long-term growth in the net asset value per share of our business. Historically, the vast majority of our operating income and cash flow has been derived from the production associated with our E&P business. However, in 2015, depressed commodity prices significantly decreased our E&P results of operations. The price we expect to receive for our production is a critical factor in the capital investments we make to develop our properties. In the fourth quarter of 2015, we decreased activity in the Appalachian Basin and the Fayetteville Shale as a result of the lower commodity price environment. Based on current forward pricing, we expect this decreased activity to continue throughout 2016. We anticipate adjusting our activity levels throughout our portfolio and are targeting a capital investment program aligned with the cash flow expected to be generated during the year. 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. We are impacted by crude oil and natural gas liquids (“NGLs”) prices, which have been volatile and have recently declined significantly. In addition to the factors identified above, the prices we realize for our production are affected by our hedging activities as well as locational differences in market prices, including basis differentials. Current 2016 forward pricing will likely result in additional impairments to our natural gas and oil properties in the second quarter of 2016 ranging from approximately $250 million to $350 million, net of taxes, when excluding future changes in costs excluded from amortization, with material impairments likely continuing beyond the second quarter.

Recent Financial and Operating Results

We reported a net loss attributable to common stock of $1.2 billion for the three months ended March 31, 2016, or ($3.03) per diluted share, compared to net income attributable to common stock of $46 million, or $0.12 per diluted share, for the three months ended March 31, 2015.

Our natural gas and liquids production increased to 237 Bcfe for the three months ended March 31, 2016, up 2% from 233 Bcfe for the three months ended March 31, 2015. The 4 Bcfe increase was due to 11 Bcf and 10 Bcfe increases in net production from our Northeast and Southwest Appalachia properties, respectively, partially offset by a 17 Bcf decrease in net production from our Fayetteville Shale and other properties. The average price realized for our gas production, including the effects of derivatives, decreased 51% to $1.48 per Mcf for the three months ended March 31, 2016, compared to $2.99 per Mcf for the same period in 2015. The average price realized for our oil production decreased 40% to $18.65 per barrel for the three months ended March 31, 2016, compared to $30.90 for the same period in 2015. The average price realized for our NGL production decreased 52% to $4.98 per barrel for the three months ended March 31, 2016, compared to $10.35 for the same period in 2015. We did not financially protect our 2016 or 2015 oil or NGL production.

Our E&P segment reported an operating loss of $1.2 billion for the three months ended March 31, 2016, down from operating income of $78 million for the three months ended March 31, 2015. This decrease was primarily due to a $1.0 billion non-cash ceiling test impairment. Excluding the impairment, our E&P segment reported an operating loss of $126 million, primarily due to a 51%, or $1.51 per Mcf, decrease in our realized natural gas price (including derivatives) along with decreases in our realized oil and NGL prices. These decreases were partially offset by a 4 Bcfe increase in production and a $115 million decrease in operating costs and expenses.

Operating income for our Midstream Services segment was $60 million for the three months ended March 31, 2016, down from $88 million for the three months ended March 31, 2015, due to a $34 million decrease in gas gathering revenues partially offset by a $6 million decrease in operating costs and expenses. In the second quarter of 2015, we sold our northeastern Pennsylvania and East Texas gathering assets that accounted for $13 million in operating income for the three months ended March 31, 2015.

Capital investments were $122 million for the three months ended March 31, 2016 (including $41 million in capitalized interest and $21 million in capitalized expenses) of which $120 million was invested in our E&P segment, compared to $1.2 billion for the same period of 2015 (including $653 million, in total, related to the acquisitions from WPX Energy, Inc. and Statoil ASA) of which $1.0 billion was invested in our E&P segment.

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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 and income tax expense are discussed on a consolidated basis.

Exploration and Production

	For the three months ended March 31,	
	2016	2015
Revenues (in millions)	$ 336	$ 655
Impairment of natural gas and oil properties (in millions)	$ 1,034	$ –
Operating costs and expenses (in millions)	$ 462	$ 577
Operating income (loss) (in millions)	$ (1,160)	$ 78
Gain on derivatives, settled (in millions) (1)	$ 8	$ 36
Gas production (Bcf)	213	219
Oil production (MBbls)	607	545
NGL production (MBbls)	3,376	1,766
Total production (Bcfe)	237	233
Average realized gas price per Mcf, including derivatives (2)	$ 1.48	$ 2.99
Average realized gas price per Mcf, excluding derivatives	$ 1.44	$ 2.63
Average realized oil price per Bbl	$ 18.65	$ 30.90
Average realized NGL price per Bbl	$ 4.98	$ 10.35
Average unit costs per Mcfe:		
Lease operating expenses	$ 0.88	$ 0.92
General & administrative expenses (3)	$ 0.19	$ 0.24
Taxes, other than income taxes (4)	$ 0.08	$ 0.12
Full cost pool amortization	$ 0.49	$ 1.15

(1) Represents the gain (loss) on settled commodity derivatives.
(2) Includes the gain (loss) on settled commodity derivatives.
(3) Excludes $58 million of restructuring charges in 2016.
(4) Excludes $3 million of restructuring charges in 2016.

Revenues

Revenues for our E&P segment were down $319 million, or 49%, for the three months ended March 31, 2016, compared to the same period in 2015. A decrease in the price realized from the sale of our natural gas production decreased revenue by $254 million. Additionally there was a decrease of $42 million in hedge settlement proceeds, a $26 million decrease as a result of decreased liquids pricing and a decrease of $16 million due to lower natural gas production volumes, partially offset by a $19 million increase due to increased liquid production volumes. For the remainder of 2016, we expect to have decreased activity in our Appalachian Basin and Fayetteville Shale assets as a result of the lower commodity price environment. Natural gas, oil, and NGL prices are difficult to predict and are subject to wide price fluctuations. As of March 31, 2016, we had protected 107 Bcf of our remaining 2016 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 Quarterly Report and to the discussion of "Commodity Prices" provided below for additional information. In May 2015, we sold our conventional oil and gas assets located in East Texas and the Arkoma Basin that accounted for $10 million of our natural gas and oil revenues for the three months ended March 31, 2015.

Production

For the three months ended March 31, 2016, our natural gas and liquids production increased 2% to 237 Bcfe, up from 233 Bcfe from the same period in 2015, and was produced entirely by our properties in the United States. The 4 Bcfe increase was due to 11 Bcf and 10 Bcfe increases in net production from our Northeast and Southwest Appalachia properties, respectively, partially offset by a 17 Bcf decrease in net production from our Fayetteville Shale and other properties. Net production from our Northeast Appalachia, Southwest Appalachia and Fayetteville Shale properties was 94 Bcf, 40 Bcfe and 103 Bcf respectively, for the three months ended March 31, 2016 compared to 83 Bcf, 30 Bcfe, and 115 Bcf, respectively, for the same period in 2015.

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Commodity Prices

The average price realized for our natural gas production, including the effects of derivatives, decreased to $1.48 per Mcf for the three months ended March 31, 2016, as compared to $2.99 for the same period in 2015. The decrease was the result of a $1.19 per Mcf decrease in the average natural gas price, excluding derivatives, and lower proceeds from our derivative program during the three months ended March 31, 2016 as compared to the same period in 2015. The average price realized for our natural gas production, excluding the effects of derivatives, decreased 45% to $1.44 per Mcf for the three months ended March 31, 2016, as compared to the same period in 2015. Our derivatives increased the average realized natural gas price by $0.04 per Mcf for the three months ended March 31, 2016 compared to an increase of $0.36 per Mcf for the same period in 2015.

Our E&P segment receives a sales price for our natural gas at a discount to average monthly NYMEX settlement prices due to heating content of the gas, locational basis differentials, transportation and fuel charges. Additionally, we receive a sales price for our oil and NGLs at a discount to average monthly West Texas Intermediate settlement and Mont Belvieu NGL composite prices, respectively, due to a number of factors including product quality, composition and types of NGLs sold, locational basis differentials, transportation and fuel charges.

We periodically enter into various hedging and other financial arrangements with respect to a portion of our projected natural gas production in order to ensure certain desired levels of cash flow and to minimize the impact of price fluctuations, including fluctuations in locational market 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 Quarterly Report for additional discussion about our derivatives and risk management activities.

Excluding the impact of derivatives, the average price received for our natural gas production for the three months ended March 31, 2016 of $1.44 per Mcf was approximately $0.65 lower than the average monthly NYMEX settlement price, primarily due to locational basis differentials and transportation costs. We protected approximately 44% of our natural gas production for the three months ended March 31, 2016 from the impact of widening basis differentials through our sales arrangements and hedging activities. For the three months ended March 31, 2016, we protected the basis on approximately 94 Bcf of our natural gas production through physical sales arrangements. We have protected basis on approximately 160 Bcf and 69 Bcf of our remaining 2016 and 2017 expected natural gas production through physical sales arrangements at a basis differential to NYMEX natural gas prices of approximately ($0.19) per Mcf and ($0.19) per Mcf for the remainder of 2016 and 2017, respectively. We had 5 Bcf of basis hedge positions in place during the first quarter of 2016. As of March 31, 2016, we had no future financial basis hedges in place.

We realized an average sales price of $18.65 per barrel for our oil production for the three months ended March 31, 2016, down 40% from $30.90 per barrel for the same period in 2015. We did not financially protect our 2016 or 2015 oil production. Oil accounted for 2% and 1% of our total production for the three months ended March 31, 2016 and 2015, respectively.

We realized an average sales price of $4.98 per barrel for our NGL production for the three months ended March 31, 2016, down 52% from $10.35 per barrel for the same period in 2015. We did not financially protect our 2016 or 2015 NGL production. NGLs accounted for 9% and 5% of our total production for the three months ended March 31, 2016 and 2015, respectively.

Operating Income

Our E&P segment reported an operating loss of $1.2 billion for the three months ended March 31, 2016, down from operating income of $78 million for the three months ended March 31, 2015. This decrease was primarily due to a $1.0 billion non-cash ceiling test impairment. Excluding the impairment, our E&P segment reported an operating loss of $126 million, primarily due to a 51%, or $1.51 per Mcf, decrease in our realized natural gas price (including derivatives) along with decreases in our realized oil and NGL prices. These decreases were partially offset by a 4 Bcfe increase in production and a $115 million decrease in operating costs and expenses. The $115 million decrease in operating costs and expenses resulted primarily from a $151 million decrease in DD&A, an $11 million decrease in general and administrative expenses, a $7 million decrease in operating expenses and a $7 million decrease in taxes other than income partially offset by a $61 million increase in restructuring charges. In May 2015, we sold our conventional oil and gas assets located in East Texas and the Arkoma Basin that accounted for $2 million of our natural gas and oil operating income for the three months ended March 31, 2015.

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Operating Costs and Expenses

Lease operating expenses per Mcfe for the E&P segment were $0.88 for the three months ended March 31, 2016, compared to $0.92 for the same period in 2015. Lease operating expenses per unit of production decreased for the three months ended March 31, 2016, as compared to the same period of 2015 primarily due to decreased gathering charges resulting from the successful renegotiation of our existing gathering and processing rates for our Southwest Appalachia production.

Excluding the restructuring charges associated with our workforce reduction, general and administrative expenses for the E&P segment were $0.19 per Mcfe for the three months ended March 31, 2016, compared to $0.24 per Mcfe for the same period in 2015 primarily due to the decrease in employee costs. In total, excluding restructuring charges, general and administrative expenses for the E&P segment were $45 million for the three months ended March 31, 2016, compared to $56 million for the three months ended March 31, 2015. Including restructuring charges, general and administrative costs for the first quarter of 2016 were $103 million for our E&P segment.

Taxes other than income taxes per Mcfe were $0.08 for the three months ended March 31, 2016 (excluding $3 million related to restructuring charges), compared to $0.12 for the same period in 2015. Taxes other than income taxes per Mcfe vary from period to period due to changes in severance and ad valorem taxes that result from the mix of our production volumes and fluctuations in commodity prices.

Our full cost pool amortization rate averaged $0.49 per Mcfe for the three months ended March 31, 2016, compared to $1.15 for the same period in 2015. 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 reserve changes.

Unevaluated costs excluded from amortization were $3.5 billion at March 31, 2016, compared to $3.7 billion at December 31, 2015. The decrease in unevaluated costs primarily resulted from our evaluation of a portion of our New Ventures assets. Unevaluated costs excluded from amortization at March 31, 2016 included $53 million related to our properties in Canada, compared to $50 million at December 31, 2015.

Midstream Services

	For the three months ended March 31, 2016	2015
	($ in millions, except volumes)	
Marketing revenues	$ 518	$ 801
Gas gathering revenues	$ 103	$ 137
Marketing purchases	$ 503	$ 786
Operating costs and expenses (1)	$ 58	$ 64
Operating income	$ 60	$ 88
Volumes marketed (Bcfe)	279	260
Volumes gathered (Bcf)	165	233

(1) Includes $3 million of restructuring charges in 2016.

Revenues

Revenues from our marketing activities were down 35% to $518 million for the three months ended March 31, 2016, compared to the same period in 2015. For the three months ended March 31, 2016, the price received for volumes marketed decreased 40% and the volumes marketed increased 7% compared to the same period in 2015. Increases and decreases in marketing revenues due to changes in commodity prices are largely offset by corresponding changes in marketing purchase expenses. Of the total natural gas volumes marketed, production from our affiliated E&P operated wells accounted for 96% and 98% of the natural gas marketed volumes for the three months ended March 31, 2016 and 2015, respectively. Our Midstream Services segment marketed approximately 67% and 40% of our combined oil and NGL production for the three months ended March 31, 2016 and 2015, respectively.

Revenues from our gathering activities were down 25% to $103 million for the three months ended March 31, 2016, compared to the same period in 2015. The decrease in gathering revenues for the three months ended March 31, 2016 was primarily due to the divestiture of our northeast Pennsylvania and East Texas gathering assets in 2015 and decreased

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volumes in the Fayetteville Shale. The divested gathering assets accounted for $20 million of our gathering revenues for the three months ended March 31, 2015.

Operating Income

Operating income from our Midstream Services segment decreased 32% to $60 million for the three months ended March 31, 2016, compared to $88 million for the same period in 2015. The $28 million decrease in operating income for the three months ended March 31, 2016 was due to a $34 million decrease in gas gathering revenues slightly offset by a $6 million decrease in operating costs and expenses. In the second quarter of 2015, we sold our northeastern Pennsylvania and East Texas gathering assets that accounted for $13 million of our operating income for the three months ended March 31, 2015.

The margin generated from marketing activities was $15 million for the three months ended March 31, 2016 and 2015. Margins are driven primarily by volumes 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. For more information about our derivatives and risk management activities, we refer you to Item 3, "Quantitative and Qualitative Disclosures About Market Risks" included in this Quarterly Report for additional information.

Restructuring Charges

In January 2016, we announced a 40% workforce reduction that was substantially concluded by the end of March 2016. Affected employees were offered a severance package which included a one-time cash payment depending on length of service and, if applicable, accelerated vesting of outstanding stock-based equity awards. As a result of this workforce reduction, we recognized restructuring charges of $64 million for the three months ended March 31, 2016.

Interest Expense

Interest expense, net of capitalization, was $14 million for the three months ended March 31, 2016, compared to $51 million for the same period in 2015. Excluding a $47 million charge for unamortized fees associated with the repayment of our bridge facility in the first quarter of 2015, interest expense, net of capitalization, increased $10 million for the three months ended March 31, 2016, compared to the same period in 2015, primarily due to an increase in our cost of debt. We capitalized interest of $41 and $48 million for the three months ended March 31, 2016 and 2015, respectively. The decrease in capitalized interest for the three months ended March 31, 2016 compared to the same period in 2015 was primarily due to the evaluation of a portion of our Southwest Appalachia assets, acquired in

December 2014.

Gain (Loss) on Derivatives

In general, our basis swaps, certain fixed price swaps, sold call options, purchased put options and interest rate swaps are not designated for hedge accounting treatment. Changes in the fair value of derivatives that are not designated for hedge accounting are recorded in gain (loss) on derivatives. We recorded a $14 million net loss on our derivatives for the three months ended March 31, 2016 consisting of a $21 million loss on unsettled derivatives partially offset by a $7 million gain on settled derivatives. For the three months ended March 31, 2015, we recorded a $14 million net gain on our derivatives consisting of a $21 million loss on unsettled derivatives more than offset by a $35 million gain on settled derivatives. We refer you to Note 7 to the unaudited condensed consolidated financial statements included in this Quarterly Report for additional detail about our gain (loss) on derivatives. In general and without consideration of volatility or duration, as 2016 natural gas prices increase from March 31, 2016 levels, we will recognize losses in future periods and, likewise, as 2016 natural gas prices decline from March 31, 2016 levels, we will recognize gains in future periods on our derivative contracts not accounted for under hedge accounting prior to settlement.

Income Taxes

Our effective tax rate was approximately 0% and 39% for the three months ended March 31, 2016 and 2015, respectively. We recorded income tax expenses of $1 million and $49 million for the three months ended March 31, 2016 and 2015, respectively. The low effective income tax rate at March 31, 2016 was the result of our recognition of a valuation allowance that reduced the deferred tax asset primarily related to our current net operating loss carryforward. A valuation allowance for deferred tax assets, including net operating losses, is recognized when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized.

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New Accounting Standards Implemented in this Report

Refer to Note 16 to the unaudited condensed consolidated financial statements of this Quarterly Report for further discussion of new accounting standards implemented.

New Accounting Standards Not Yet Implemented in this Report

Refer to Note 16 to the unaudited condensed consolidated financial statements of this Quarterly Report for a discussion of new accounting standards which have not yet been implemented.

LIQUIDITY AND CAPITAL RESOURCES

We depend primarily on internally generated funds, our $2.0 billion revolving credit facility, funds accessed through term loans such as our $750 million term loan facility, our cash and cash equivalents balance and capital markets as our primary sources of liquidity.

In the first quarter of 2016, we decreased activity in the Appalachian Basin and Fayetteville Shale as a result of the low commodity price environment. Based on current forward pricing, we expect this decreased activity to continue throughout 2016. Accordingly, we anticipate adjusting our activity levels and are targeting a capital investment program aligned with the cash flow expected to be generated during the year. We have the financial flexibility to draw on a portion of the funds available under our revolving credit facility or cash and cash equivalents balance to fund the portion of our planned capital investments exceeding our operating cash flow as necessary (discussed below under “Capital Investments”). We refer you to Note 10 of the unaudited condensed consolidated financial statements included in this Quarterly Report and the section below under “Financing Requirements” for additional discussion of our revolving credit facility and commercial paper program.

At March 31, 2016, our capital structure consisted of 81% net debt and 19% equity, excluding $23 million and $3 million of unamortized issuance cost and unamortized debt discount, respectively. This temporary high level of debt resulted from a drawdown of $1.55 billion on our revolving credit facility on March 30, 2016 that was repaid on April 1, 2016. As part of our ongoing review of options to address our long-term debt maturities, having the cash from the $1.55 borrowing as an asset on our consolidated balance sheet as of the last day of the first quarter of 2016 expanded our flexibility by increasing the maximum amount of our secured debt or debt of our subsidiaries that may be incurred during the second quarter of 2016 in accordance with our credit facilities and indentures, if we should decide to utilize debt of these types to retire, rearrange or extend existing debt and credit facilities. We believe that our operating cash flow and available funds under our revolving credit facility along with our cash and cash equivalents will be adequate to meet our capital and operating requirements for the remainder of 2016. If we do not have adequate liquidity or are unable to obtain financing on favorable terms or at all, however, we may not be able to make intended capital investments, which could restrict our ability to grow and could have a material adverse effect on our results of operations, cash flows and financial condition. Additionally, our ability to make payments on and to refinance our indebtedness will depend on our ability to generate cash in the future. The credit status of the financial institutions participating in our revolving credit facility could adversely impact our ability to borrow funds under the revolving 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 their obligation to us. We refer you to the section below under "Financing Requirements" for additional discussion of our compliance with the covenants of our revolving credit and term loan facilities.

Net cash provided by operating activities decreased 83% to $92 million for the three months ended March 31, 2016, down from $541 million for the same period in 2015, due to a decrease in net income adjusted for non-cash expenses and changes in working capital accounts. During the three months ended March 31, 2016, requirements for our capital investments were funded primarily from our cash generated by operating activities, net proceeds from borrowings under our revolving credit facility, commercial paper, and cash and cash equivalents. For the three months ended March 31, 2016, net cash generated from operating activities provided 75% of our cash requirements for capital investments, compared to 46% for the same period in 2015.

Our cash flow from operating activities is highly dependent upon the sales prices that we receive for our natural gas and liquids production. Natural gas, oil and NGL prices are subject to wide fluctuations and are driven by market supply and demand, which is impacted by many factors. The sales price we receive for our production is also influenced by our commodity hedging activities. See "Quantitative and Qualitative Disclosures about Market Risks" in Item 3 and Note 7 to the unaudited condensed consolidated financial statements included in this Quarterly Report for further details. 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 co-owners. 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 co-owners could adversely impact our cash flows.

Due to these 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. Further, we may from time to time seek to retire or rearrange some or all of our outstanding debt or preferred stock through cash purchases, and/or exchanges, open market purchases, privately negotiated transactions, tender offers or otherwise. Such transactions, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Capital Investments

Our capital investments for the three months ended March 31, 2016 were $122 million and $1.2 billion for the three months ended March 31, 2015, which included $653 million, in total, related to acquisitions from WPX Energy, Inc. (“WPX”) and Statoil ASA (“Statoil”). Our E&P segment investments were $120 million and $1.0 billion for the three months ended March 31, 2016 and 2015, respectively. Our E&P segment capitalized internal costs of $27 million for the three months ended March 31, 2016 compared to $86 million for the comparable period in 2015. 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.

Overall planned capital investments for 2016 are expected to range between $350 million and $400 million. We anticipate adjusting our activity levels throughout our portfolio and are targeting a capital investment aligned with the cash flow expected to be generated during the year. Although our 2016 capital investment program has been, and is expected to continue to be funded through cash flow from operations, we have the financial flexibility to utilize borrowings under our revolving credit facility along with our cash and cash equivalents.

Financing Requirements

Our total debt outstanding was $6.5 billion at March 31, 2016, compared to $4.7 billion at December 31, 2015. The increase at March 31, 2016 related primarily to short-term borrowing on our revolving credit facility of $1.55 billion on March 30, 2016 that was repaid on April 1, 2016. As part of our ongoing review of options to address our long-term debt maturities, having the cash from the $1.55 borrowing as an asset on our consolidated balance sheet as of the last day of the first quarter of 2016 expanded our flexibility by increasing the maximum amount of our secured debt or debt of our subsidiaries that may be incurred during the second quarter of 2016 in accordance with our credit facilities and indentures, if we should decide to utilize debt of these types to retire, rearrange or extend existing debt and credit facilities. See Note 2 and Note 10 to the unaudited condensed consolidated financial statements included in this Quarterly Report for further details.

In November 2015, we entered into a $750 million unsecured three-year term loan credit agreement with various lenders that was used to repay borrowings under the revolving credit facility. The interest rate on the term loan facility is determined based upon our public debt ratings from S&P and Moody’s and was 162.5 basis points over the London Interbank Offered Rate (“LIBOR”) as of March 31, 2016. The term loan facility requires prepayment under certain circumstances from the net cash proceeds of sales of equity or certain assets and borrowings outside the ordinary course of business.

In April 2015, we entered into a commercial paper program which allowed us to issue up to $2.0 billion in commercial paper, provided that outstanding borrowings from our commercial paper program, combined with outstanding borrowings under our revolving credit facility, not exceed $2.0 billion. The commercial paper issuance had terms of up to 397 days and carried interest at rates agreed upon at the time of each issuance. As of March 31, 2016, we had no outstanding issuances under our commercial paper program and have no plans of utilizing the commercial paper market for the remainder of 2016.

In January 2015, we completed concurrent underwritten public offerings of 30,000,000 shares of common stock and 34,500,000 depositary shares (both share counts include shares issued as a result of the underwriters exercising their options to purchase additional shares). Net proceeds from the offerings totaled approximately $2.3 billion after underwriting discount and expenses. Each depositary share represents a 1/20th interest in a share of our mandatory

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convertible preferred stock, with a liquidation preference of $1,000 per share (equivalent to a $50 liquidation preference per depositary share). The proceeds from the offerings were used to partially repay borrowings under a $4.5 billion 364-day bridge facility that we entered into in December 2014 in connection with our acquisition of assets in Southwest Appalachia, with the remaining balance fully repaid with proceeds from our January 2015 public offering of $2.2 billion in senior notes.

The mandatory convertible preferred stock entitles the holders to a proportional fractional interest in the rights and preferences of the convertible preferred stock, including conversion, dividend, liquidation and voting rights. Dividends are to be paid at a rate of 6.25% per annum on the liquidation preference of $1,000 per share and can be paid in cash, common stock or a combination of both. Unless converted earlier at the option of the holders, on or around January 15, 2018 each share of convertible preferred stock will automatically convert into between 37.0028 and 43.4782 shares of our common stock (and, correspondingly, each depositary share will convert into between 1.85014 and 2.17391 shares of our common stock), subject to customary anti-dilution adjustments, depending on the volume-weighted average price of our common stock over a 20 trading-day period immediately prior to that date.

Our mandatory convertible preferred stock has the non-forfeitable right to participate on an as-converted basis at the conversion rate then in effect in any common stock dividends declared and as such, is considered a participating security. As such, it is included in the computation of basic and diluted earnings per share, pursuant to the two-class method. In the calculation of basic earnings per share attributable to common shareholders, participating securities are allocated earnings based on actual dividend distributions received plus a proportionate share of undistributed net income attributable to common shareholders, if any, after recognizing distributed earnings.

In January 2015, we completed a public offering of $350 million aggregate principal amount of our 3.30% senior notes due 2018 (the “2018 Notes”), $850 million aggregate principal amount of our 4.05% senior notes due 2020 (the “2020 Notes”) and $1.0 billion aggregate principal amount of our 4.95% senior notes due 2025 (the “2025 Notes” and together with the 2018 and 2020 Notes, the “Notes”), with net proceeds from the offering totaling approximately $2.2 billion after underwriting discounts and offering expenses. The proceeds from the sale of the Notes were used to repay all principal and interest remaining outstanding under our $4.5 billion 364-day bridge facility, which was first reduced with proceeds from our concurrent underwritten public offerings of common stock and depositary shares. Proceeds from the sale of the Notes were also used to repay a portion of amounts outstanding under our revolving credit facility. The Notes were sold to the public at a price of 99.949% of their face value for the 2018 Notes, 99.897% of their face value for the 2020 Notes and 99.782% of their face value for the 2025 Notes. The interest rates on the Notes is determined based on our public debt ratings from S&P and Moody’s. Downgrades from either rating agency increase our interest costs by 25.0 basis points per downgrade level on the following semi-annual bond interest payment. Based on the February 2016 downgrades from S&P and Moody’s, our interest rates on these notes will increase by 125.0 basis points effective July 2016. As a result of the downgrade, our interest expense for 2016 will increase $14 million.

In December 2013, we entered into a credit agreement that exchanged our previous revolving credit facility. Under the revolving credit facility, we have a borrowing capacity of $2.0 billion reduced for outstanding letters of credit. We had $148 million in letters of credit outstanding as of March 31, 2016. The amount available under our credit facility could be further reduced by up to $250 million related to potential requirements to post additional letters of credit. Our current revolving credit facility has a maturity date of December 2018. The interest rate on the revolving credit facility is determined based upon our public debt ratings from S&P and Moody's and was 200 basis points over LIBOR as of March 31, 2016. The revolving credit facility is unsecured and is not guaranteed by any of our subsidiaries. Contemporaneously with the execution of the credit agreement, in December 2013, we obtained releases of subsidiary guarantees under the 7.15%, 7.5%, 7.35%, 7.125% and 4.10% senior notes.

At March 31, 2016, we had a long-term issuer credit rating of BB+ by S&P and a long-term debt rating of B1 by Moody's. Any further downgrades in our public debt ratings by S&P or Moody's could increase our cost of funds and decrease our liquidity under the revolving credit facility.

Our revolving credit and term loan facilities contain covenants that impose certain restrictions on us. Under our revolving credit and term loan facilities, 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 non-cash impacts from any full cost ceiling impairments, certain non-cash hedging activities, unamortized issuance cost, unamortized debt discount and our pension and other postretirement liabilities. Therefore, under our revolving credit and term loan facilities, our adjusted capital structure as of March 31, 2016, was 45% debt and 55% equity. We were in compliance with all of the covenants of our revolving credit and term loan facilities as of March 31, 2016.
Although we do not anticipate any violations of our financial covenants, our ability to comply with these 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 revolving credit facility, we may have to decrease our capital investment plans.

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At March 31, 2016, our capital structure consisted of 81% net debt and 19% equity (including $1,597 million in cash and cash equivalents), compared to 67% net debt and 33% equity (including $15 million in cash and cash equivalents) at December 31, 2015.

Our derivative contracts allow us to ensure a certain level of cash flow to fund our operations. At April 19, 2016, we had NYMEX commodity price derivatives in place on 107 Bcf of our remaining targeted 2016 natural gas production. The amount of long-term debt we incur will be largely dependent upon commodity prices and our capital investment plans.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of March 31, 2016, our material off-balance sheet arrangements and transactions include operating lease arrangements. There are no other transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect our liquidity or availability of our capital resources. For more information regarding off-balance sheet arrangements, we refer you to "Contractual Obligations and Contingent Liabilities and Commitments" in our 2015 Annual Report.

Contractual Obligations and Contingent Liabilities and Commitments

We have various contractual obligations in the normal course of our operations and financing activities. Other than the firm transportation agreements discussed below, there have been no material changes to our contractual obligations from those disclosed in our 2015 Annual Report.

Contingent Liabilities and Commitments

As of March 31, 2016, our contractual obligations for demand and similar charges under firm transportation and gathering agreements to guarantee access capacity on natural gas and liquids pipelines and gathering systems totaled approximately $8.6 billion, $3.3 billion of which related to access capacity on future pipeline and gathering infrastructure projects that still require the granting of regulatory approvals and/or additional construction efforts. This amount also included guarantee obligations of up to $861 million. As of March 31, 2016, future payments under non-cancelable firm transportation and gathering agreements are as follows:

	Payments Due by Period				
	Total	Less than 1	1 to 3 Years	3 to 5 Years	More than 5

		Year			Years
	(in millions)				
Infrastructure Currently in Service	$ 5,305	$ 591	$ 1,164	$ 932	$ 2,618
Infrastructure Pending Regulatory Approval and/or Construction (1)	3,311	10	200	444	2,657
Total Transportation and Gathering Charges	$ 8,616	$ 601	$ 1,364	$ 1,376	$ 5,275

(1) Based on the estimated in-service dates as of March 31, 2016.

Substantially all of our employees are covered by defined benefit and postretirement benefit plans. For the three months ended March 31, 2016, we have contributed $3 million to the pension and postretirement benefit plans. In January 2016, the Company initiated a reduction in workforce that was effectively completed by the end of the first quarter. As a result of the workforce reduction, the Company continues to evaluate its pension and other postretirement benefit funding requirements and will disclose its funding plans once reasonably determined. As of March 31, 2016 and December 31, 2015, we recognized a liability of $50 million as a result of the underfunded status of our pension and other postretirement benefit plans.

We are subject to litigation, claims and proceedings that arise 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 are 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 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, we refer you to "Legal Proceedings" in Item 1 of Part II of this Quarterly Report.

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We are also 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 our financial position or results of operations.

Working Capital

We maintain access to funds that may be needed to meet capital requirements through our revolving credit facility described in "Financing Requirements" above. We had positive working capital of $1,406 million at March 31, 2016 and negative working capital of $314 million at December 31, 2015. The positive working capital as of March 31, 2016 was primarily due to $1.55 billion of marketable securities borrowed on our revolving credit facility and paid back on April 1, 2016. The negative working capital as of December 31, 2015 was primarily due to a decrease in derivative assets in 2015.

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 fixed price swap agreements, fixed price options, basis swaps and interest rate swaps to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas and interest rates. Our Board of Directors has approved risk management policies and procedures to utilize financial products for the reduction of defined commodity price risk. Utilization of financial products for the reduction of interest rate risks is subject to the approval of our Board of Directors. These policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings.

Credit Risk

Our financial instruments that are exposed to concentrations of credit risk consist primarily of trade receivables and derivative contracts associated with commodities trading. Concentrations of credit risk with respect to receivables are limited due to the large number of our purchasers and their dispersion across geographic areas. No single purchaser accounted for greater than 10% of revenues for the three months ended March 31, 2016. See "Commodities Risk" below for discussion of credit risk associated with commodities trading.

Interest Rate Risk

At March 31, 2016, we had approximately $3.9 billion of outstanding senior notes with a weighted average interest rate of 4.817%, $750 million of term loan facility debt with a variable interest rate of 2.025%, $1,852 million of borrowings under our revolving credit facility with a variable interest rate of 4.154%, and no outstanding balance on our commercial paper program. The increase in borrowings on our revolving credit facility at March 31, 2016 related primarily to short-term borrowing of $1.55 billion on March 30, 2016 that was repaid on April 1, 2016. We currently have an interest rate swap in effect to mitigate a portion of our exposure to volatility in interest rates.

Commodities Risk

We use over-the-counter fixed price swap agreements and options to protect sales of our production against the inherent risks of adverse price fluctuations or locational pricing differences between a published index and the NYMEX futures market. These swaps and options include 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) and transactions in which parties agree to pay a price based on two different indices (referred to as basis swaps). For additional information on our derivatives and risk management, see Note 7 in the unaudited condensed consolidated financial statements included in this Quarterly Report.

The primary market risks relating to our derivative contracts are the volatility in market prices and basis differentials for natural gas. However, the market price risk is offset by the gain or loss recognized upon the related sale or purchase of the natural gas that is financially protected. Credit risk relates to the risk of loss as a result of non-performance by our counterparties. The counterparties are primarily major banks and integrated energy companies that 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, we cannot be certain that we will not experience such losses in the future.

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Item 4. Controls and Procedures.

Disclosure Controls and Procedures

We have performed an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures, as defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act. Our disclosure controls and procedures are the controls and other procedures that we have designed to ensure that we record, process, accumulate and communicate information to our management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosures and submission within the time periods specified in the SEC's rules and forms. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those determined to be effective can provide only a level of reasonable assurance with respect to financial statement preparation and presentation. Based on the evaluation, our management, including our Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures were effective as of March 31, 2016 at a reasonable assurance level.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the quarter ended March 31, 2016 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.

Refer to "Litigation" and "Environmental Risk" in Note 11 to the unaudited condensed consolidated financial statements included in Item 1 of Part I of this Quarterly Report for a discussion of the Company's legal proceedings.

ITEM 1A. RISK FACTORS.

There were no additions or material changes to our risk factors as disclosed in Item 1A of Part I in the Company's 2015 Annual Report.

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 Quarterly Report.

ITEM 5. OTHER INFORMATION.

Not applicable.

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ITEM 6. EXHIBITS.

(10.1)	Southwestern Energy Company 2013 Incentive Plan Form of Performance Unit Award Agreement.
(10.2)	Retirement Agreement dated January 11, 2016 between Southwestern Energy Company and Steven L. Mueller. (Incorporated by reference to Exhibit 10.38 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2015)
(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 furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(32.2)	Certification of 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:	April 21, 2016	/s/ R. CRAIG OWEN
		R. Craig Owen Senior Vice President and Chief Financial Officer