SM Energy Co
Form 10-Q
May 06, 2015

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

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2015
Commission File Number 001-31539
SM ENERGY COMPANY
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	41-0518430 (I.R.S. Employer Identification No.)
1775 Sherman Street, Suite 1200, Denver, Colorado (Address of principal executive offices)	80203 (Zip Code)

(303) 861-8140
(Registrant's telephone number, including area code)

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 þ No o

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 þ No o

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 þ	Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

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

As of April 29, 2015, the registrant had 67,464,185 shares of common stock, $0.01 par value, outstanding.

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ITEM 1. FINANCIAL STATEMENTS
SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)
(in thousands, except share amounts)

	March 31, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$22	$120
Accounts receivable	270,841	322,630
Derivative asset	380,633	402,668
Prepaid expenses and other	18,147	19,625
Total current assets	669,643	745,043
Property and equipment (successful efforts method):		
Proved oil and gas properties	7,006,832	7,348,436
Less - accumulated depletion, depreciation, and amortization	(2,865,627)	(3,233,012)
Unproved oil and gas properties	512,461	532,498
Wells in progress	459,806	503,734
Oil, gas, and other property and equipment held for sale net of accumulated depletion, depreciation and amortization of $580,637 and $22,482, respectively	184,951	17,891
Other property and equipment, net of accumulated depreciation of $35,590 and $37,079, respectively	344,670	334,356
Total property and equipment, net	5,643,093	5,503,903
Noncurrent assets:		
Derivative asset	204,841	189,540
Other noncurrent assets	83,109	78,214
Total other noncurrent assets	287,950	267,754
Total Assets	$6,600,686	$6,516,700
LIABILITIES AND STOCKHOLDERS’ EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$561,051	$640,684
Deferred tax liability	135,204	142,976
Other current liabilities	—	1,000
Total current liabilities	696,255	784,660
Noncurrent liabilities:		
Revolving credit facility	416,500	166,000
Senior Notes (note 5)	2,200,000	2,200,000
Asset retirement obligation	108,815	120,429
Asset retirement obligation associated with oil and gas properties held for sale	14,286	438
Net Profits Plan liability	22,802	27,136
Deferred income taxes	865,726	891,681
Derivative liability	398	70
Other noncurrent liabilities	39,676	39,631
Total noncurrent liabilities	3,668,203	3,445,385

Commitments and contingencies (note 6)		
Stockholders' equity:		
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued and outstanding: 67,464,185 and 67,463,060, respectively	675	675
Additional paid-in capital	289,294	283,295
Retained earnings	1,957,747	2,013,997
Accumulated other comprehensive loss	(11,488)	(11,312)
Total stockholders' equity	2,236,228	2,286,655
Total Liabilities and Stockholders' Equity	$6,600,686	$6,516,700

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

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SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)
(in thousands, except per share amounts)

	For the Three Months Ended March 31,	
	2015	2014
Operating revenues:		
Oil, gas, and NGL production revenue	$393,315	$623,109
Gain (loss) on divestiture activity	(35,802)	2,958
Other operating revenues	8,421	6,653
Total operating revenues and other income	365,934	632,720
Operating expenses:		
Oil, gas, and NGL production expense	196,151	163,709
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	217,401	177,215
Exploration	37,407	21,335
Impairment of proved properties	55,526	—
Abandonment and impairment of unproved properties	11,627	2,801
General and administrative	43,639	35,051
Change in Net Profits Plan liability	(4,334)	(1,776)
Derivative (gain) loss	(154,167)	97,662
Other operating expenses	17,119	8,089
Total operating expenses	420,369	504,086
Income (loss) from operations	(54,435)	128,634
Non-operating income (expense):		
Other, net	571	26
Interest expense	(32,647)	(24,190)
Income (loss) before income taxes	(86,511)	104,470
Income tax (expense) benefit	33,453	(38,863)
Net income (loss)	$(53,058)	$65,607
Basic weighted-average common shares outstanding	67,463	67,056
Diluted weighted-average common shares outstanding	67,463	68,126
Basic net income (loss) per common share	$(0.79)	$0.98
Diluted net income (loss) per common share	$(0.79)	$0.96
Dividends per common share	$0.05	$0.05

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS) (UNAUDITED)
(in thousands)

	For the Three Months Ended March 31,	
	2015	2014
Net income (loss)	$(53,058)	$65,607
Other comprehensive income (loss), net of tax:		
Pension liability adjustment	(176)	—
Total other comprehensive income (loss), net of tax	(176)	—
Total comprehensive income (loss)	$(53,234)	$65,607

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)
(in thousands)

	For the Three Months Ended March 31,	
	2015	2014
Cash flows from operating activities:		
Net income (loss)	$(53,058)	$65,607
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
(Gain) loss on divestiture activity	35,802	(2,958)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	217,401	177,215
Exploratory dry hole expense	16,275	—
Impairment of proved properties	55,526	—
Abandonment and impairment of unproved properties	11,627	2,801
Stock-based compensation expense	6,024	6,344
Change in Net Profits Plan liability	(4,334)	(1,776)
Derivative (gain) loss	(154,167)	97,662
Derivative cash settlements	160,133	(28,940)
Amortization of deferred financing costs	1,957	1,477
Deferred income taxes	(33,727)	38,374
Plugging and abandonment	(2,425)	(1,325)
Other, net	1,496	(3,103)
Changes in current assets and liabilities:		
Accounts receivable	69,527	9,347
Prepaid expenses and other	1,281	885
Accounts payable and accrued expenses	(45,416)	(61,882)
Net cash provided by operating activities	283,922	299,728
Cash flows from investing activities:		
Net proceeds from sale of oil and gas properties	21,573	1,979
Capital expenditures	(544,965)	(351,934)
Acquisition of proved and unproved oil and gas properties	(10,069)	195
Other, net	(997)	4,227
Net cash used in investing activities	(534,458)	(345,533)
Cash flows from financing activities:		
Proceeds from credit facility	560,000	—
Repayment of credit facility	(309,500)	—
Other, net	(62)	(8)
Net cash provided by (used in) financing activities	250,438	(8)
Net change in cash and cash equivalents	(98)	(45,813)
Cash and cash equivalents at beginning of period	120	282,248
Cash and cash equivalents at end of period	$22	$236,435

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED) (Continued)

Supplemental schedule of additional cash flow information and non-cash investing and financing activities:

	For the Three Months Ended March 31,	
	2015	2014
	(in thousands)	
Cash paid for interest, net of capitalized interest	$34,059	$37,851
Net cash paid (refunded) for income taxes	$94	$(14)

Dividends of approximately $3.4 million were declared by the Company’s Board of Directors, but not paid, as of March 31, 2015, and 2014.

As of March 31, 2015, and 2014, $318.0 million and $200.5 million, respectively, of accrued capital expenditures were included in accounts payable and accrued expenses in the Company’s condensed consolidated balance sheets. These oil and gas property additions are reflected in cash used in investing activities in the periods during which the payables are settled.

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

SM ENERGY COMPANY AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

Note 1 - The Company and Business

SM Energy Company ("SM Energy" or the "Company") is an independent energy company engaged in the acquisition, exploration, development, and production of crude oil and condensate, natural gas, and natural gas liquids (also respectively referred to as "oil," "gas," and "NGLs" throughout this report) in onshore North America.

Note 2 - Basis of Presentation, Significant Accounting Policies, and Recently Issued Accounting Standards

Basis of Presentation

The accompanying unaudited condensed consolidated financial statements of SM Energy have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP") for interim financial information and the instructions to Form 10-Q and Regulation S-X. They do not include all information and notes required by GAAP for complete financial statements. However, except as disclosed herein, there has been no material change in the information disclosed in the notes to consolidated financial statements included in SM Energy's Annual Report on Form 10-K for the year ended December 31, 2014 (the "2014 Form 10-K"). In the opinion of management, all adjustments, consisting of normal recurring accruals considered necessary for a fair presentation of interim financial information, have been included. Operating results for the periods presented are not necessarily indicative of expected results for the full year. In connection with the preparation of its unaudited condensed consolidated financial statements, the Company evaluated events subsequent to the balance sheet date of March 31, 2015, through the filing date of this report. Certain prior period amounts have been reclassified to conform to the current presentation on the accompanying financial statements. The asset retirement obligation associated with oil and gas properties held for sale has been separately presented within the accompanying condensed consolidated balance sheets ("accompanying balance sheets").

Significant Accounting Policies

The significant accounting policies followed by the Company are set forth in Note 1 to the Company's consolidated financial statements in its 2014 Form 10-K, and are supplemented by the notes to the unaudited condensed consolidated financial statements in this report. These unaudited condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes included in the 2014 Form 10-K.

Recently Issued Accounting Standards

Effective January 1, 2015, the Company early adopted, on a prospective basis, Financial Accounting Standards Board ("FASB") Accounting Standards Update ("ASU") No. 2015-01, "Income Statement – Extraordinary and Unusual Items." This ASU simplifies income statement presentation by eliminating the concept of extraordinary items. There was no impact to the Company's financial statements or disclosures from the adoption of this standard.

In April 2015, the FASB issued new authoritative accounting guidance requiring debt issuance costs to be presented on the balance sheet as a direct deduction from the carrying value of the related debt liability. This guidance is to be applied using a retrospective method and is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2015. Early application is permitted. The Company is currently evaluating the provisions of this guidance and assessing its impact on the Company's financial statements and disclosures.

There are no other new significant accounting standards applicable to the Company that have been issued but not yet adopted by the Company as of March 31, 2015, and through the filing date of this report that have not been disclosed above or included within the 2014 Form 10-K.

Note 3 – Assets Held for Sale

Assets are classified as held for sale when the Company commits to a plan to sell the assets and there is reasonable certainty the sale will take place within one year. Upon classification as held for sale, long-lived assets are no longer depreciated or depleted, and a measurement for impairment is performed to identify and expense any excess of carrying value over fair value less estimated costs to sell. Subsequent decreases to the estimated fair value less the costs to sell impact the measurement of assets held for sale.

As of March 31, 2015, the accompanying balance sheets present $185.0 million of assets held for sale, net of accumulated depletion, depreciation, and amortization expense, which primarily consists of all of the Company's Mid-Continent region assets. A corresponding asset retirement obligation liability of $14.3 million is separately presented. Earlier in 2015, the Company announced plans to divest of these assets and shift resources to further focus on development of core assets. Write-downs to fair value less estimated costs to sell of $30.0 million for certain of these assets for the three months ended March 31, 2015, are reflected in the gain (loss) on divestiture activity line item in the accompanying condensed consolidated statements of operations ("accompanying statements of operations").

Subsequent to March 31, 2015, the Company entered into purchase and sale agreements with two separate buyers for the sale of its Mid-Continent assets that were classified as held for sale at March 31, 2015. The Company expects to close these transactions in the second quarter of 2015 for a total purchase price of approximately $324 million, subject to customary closing adjustments. The closings of these transactions are subject to the satisfaction of customary closing conditions, and there can be no assurance that either of these transactions will close on the expected closing dates or at all.

The Company determined that these planned asset sales do not qualify for discontinued operations accounting under financial statement presentation authoritative guidance.

In conjunction with the Company's efforts to divest its Mid-Continent region assets, the Company announced the planned closure of its Tulsa, Oklahoma office in 2015 with the relocation of certain personnel to other Company offices. The Company anticipates incurring approximately $10 million of exit and disposal costs associated with the severance, retention and relocation of employees, termination of operating leases, vacant office space, and other expenses. The majority of these exit and disposal activities are expected to be completed by the end of the third quarter of 2015. As of March 31, 2015, the Company had recorded $3.5 million of exit and disposal costs, the majority of which were recorded as general and administrative expense within the accompanying statements of operations.

Note 4 - Income Taxes

Income tax (benefit) expense for the three months ended March 31, 2015, and 2014, differs from the amount that would be provided by applying the statutory United States federal income tax rate to income before income taxes primarily due to the effect of state income taxes, changes in valuation allowances, percentage depletion, research and development ("R&D") credits, and other permanent differences. The quarterly rate can also be impacted by the proportional effects of forecasted net income as of each period end presented.

The provision for income taxes consists of the following:

	For the Three Months Ended March 31,			
	2015		2014	
	(in thousands)			
Current portion of income tax expense:				
Federal	$—		$—	
State	274		489	
Deferred portion of income tax (benefit) expense	(33,727	)	38,374	
Total income tax (benefit) expense	$(33,453	)	$38,863	
	38.7	%	37.2	%

A change in the Company's effective tax rate between reported periods will generally reflect differences in its estimated highest marginal state tax rate due to changes in the composition of income from Company activities among various state tax jurisdictions. Cumulative effects of state rate changes are reflected in the period legislation is enacted.

The Company is generally no longer subject to United States federal or state income tax examinations by tax authorities for years before 2007. During the first quarter of 2015, as a result of its R&D credit settlement with the IRS Appeals Office in late 2014, the Company recorded an additional $2.0 million net R&D credit from a claim filed on an amended return. No R&D credit was recorded in 2014.

Note 5 - Long-term Debt

Revolving Credit Facility

The Company's Second Amendment to the Fifth Amended and Restated Credit Agreement dated December 10, 2014, provides a maximum loan amount of $2.5 billion, current aggregate lender commitments of $1.5 billion, and a maturity date of December 10, 2019. The borrowing base is subject to regular semi-annual redeterminations and was reaffirmed by the Company's lenders on April 6, 2015, at $2.4 billion. The borrowing base redetermination process under the credit facility considers the value of the Company's proved oil and gas properties, as determined by the Company's lenders. The next redetermination date is scheduled for October 1, 2015. Borrowings under the facility are secured by mortgages on assets having a value equal to at least 75 percent of the total value of the Company's proved oil and gas properties.

The Company must comply with certain financial and non-financial covenants under the terms of its credit facility agreement, including limitations on the payment of dividends to $50.0 million per year. The Company was in compliance with all covenants under the credit facility as of March 31, 2015, and through the filing date of this report.

The following table presents the outstanding balance, total amount of letters of credit, and available borrowing capacity under the Company's credit facility as of April 29, 2015, March 31, 2015, and December 31, 2014:

	As of April 29, 2015	As of March 31, 2015	As of December 31, 2014
	(in thousands)		
Credit facility balance	$502,500	$416,500	$166,000
Letters of credit [1]	$808	$808	$808
Available borrowing capacity	$996,692	$1,082,692	$1,333,192

[1] Letters of credit reduce the amount available under the credit facility on a dollar-for-dollar basis.

Senior Notes

The Senior Notes line on the accompanying balance sheets represents the outstanding principal amount of the 6.625% Senior Notes due 2019 (the "2019 Notes"), the 6.50% Senior Notes due 2021 (the "2021 Notes"), the 6.125% Senior Notes due 2022 (the "2022 Notes"), the 6.50% Senior Notes due 2023 (the "2023 Notes"), and the 5.0% Senior Notes due 2024 (the "2024 Notes" and collectively with the 2019 Notes, 2021 Notes, 2022 Notes, and 2023 Notes, the "Senior Notes"), as shown in the table below:

	As of March 31, 2015	As of December 31, 2014
	(in thousands)	
2019 Notes	$350,000	$350,000
2021 Notes	350,000	350,000
2022 Notes	600,000	600,000
2023 Notes	400,000	400,000
2024 Notes	500,000	500,000
Total Senior Notes	$2,200,000	$2,200,000

The Senior Notes are unsecured senior obligations and rank equal in right of payment with all of the Company's existing and any future unsecured senior debt, and are senior in right of payment to any future subordinated debt. There are no subsidiary guarantors of the Senior Notes. The Company is subject to certain covenants under the indentures governing the Senior Notes that limit the Company's ability to incur additional indebtedness, issue preferred stock, and make restricted payments, including dividends; provided, however, that the first $6.5 million of dividends paid each year are not restricted by the restricted payment covenant. The Company was in compliance with all covenants under its Senior Notes as of March 31, 2015, and through the filing date of this report.

Note 6 - Commitments and Contingencies

Commitments

There have been no material changes in commitments during the first quarter of 2015. Please refer to Note 6 - Commitments and Contingencies in the Company’s 2014 Form 10-K for additional discussion.

Contingencies

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

Note 7 - Compensation Plans

Performance Share Units Under the Equity Incentive Compensation Plan

The Company grants performance share units (“PSUs”) to eligible employees as part of its equity compensation program. The number of shares of the Company’s common stock issued to settle PSUs ranges from 0% to 200% of the number of PSUs awarded and is determined based on the Company’s performance over a three-year measurement period. The performance criteria for the PSUs are based on a combination of the Company’s annualized total shareholder return (“TSR”) for the performance period and the relative performance of the Company’s TSR compared with the annualized TSR of certain peer companies for the performance period. PSUs are recognized as general and administrative and exploration expense over the vesting periods of the award.

Total expense recorded for PSUs for the three months ended March 31, 2015, and 2014, was $2.3 million and $3.2 million, respectively. As of March 31, 2015, there was $18.1 million of total unrecognized compensation expense related to unvested PSU awards, which is being amortized through 2017. There have been no material changes to the outstanding and non-vested PSUs during the three months ended March 31, 2015.

Restricted Stock Units Under the Equity Incentive Compensation Plan

The Company grants restricted stock units (“RSUs”) as part of its equity compensation program. Each RSU represents a right for one share of the Company’s common stock to be delivered upon settlement of the award at the end of the specified vesting period. RSUs are recognized as general and administrative expense and exploration expense over the vesting periods of the award.

Total expense recorded for RSUs for the three months ended March 31, 2015, and 2014, was $2.9 million and $2.8 million, respectively. As of March 31, 2015, there was $19.3 million of total unrecognized compensation expense related to unvested RSU awards, which is being amortized through 2017. There have been no material changes to the outstanding and non-vested RSUs during the three months ended March 31, 2015.

Net Profits Plan

Cash payments made or accrued under the Company’s Net Profits Plan totaled $1.3 million and $3.3 million for the three months ended March 31, 2015, and 2014, respectively, the majority of which were recorded as general and administrative expense within the accompanying statements of operations.

The Company records changes in the present value of estimated future payments under the Net Profits Plan as a separate line item in the accompanying statements of operations. The change in the estimated liability is recorded as a non-cash expense or benefit in the current period. The amount recorded as an expense or benefit associated with the change in the estimated liability is not allocated to general and administrative expense or exploration expense because it is associated with the future net cash flows from oil and gas properties in the respective pools rather than results being realized through current period production. If the Company allocated the change in liability to these specific functional line items, based on the current allocation of actual distributions made by the Company, such expenses or benefits would predominately be allocated to general and administrative expense. As time has passed, the amount distributed relating to prospective exploration efforts has become insignificant as more is paid to employees that have terminated employment and do not provide ongoing exploration support to the Company.

Note 8 - Pension Benefits

Pension Plans

The Company has a non-contributory pension plan covering substantially all employees who meet age and service requirements (the “Qualified Pension Plan”). The Company also has a supplemental non-contributory pension plan covering certain management employees (the “Nonqualified Pension Plan” and together with the Qualified Pension Plan, the “Pension Plans”).

Components of Net Periodic Benefit Cost for the Pension Plans

The following table presents the components of the net periodic benefit cost for the Pension Plans:

	For the Three Months Ended March 31,	
	2015	2014
	(in thousands)	
Service cost	$1,584	$1,573
Interest cost	548	407
Expected return on plan assets that reduces periodic pension costs	(494)	(385)
Amortization of prior service costs	4	4
Amortization of net actuarial loss	172	306
Net periodic benefit cost	$1,814	$1,905

Prior service costs are amortized on a straight-line basis over the average remaining service period of active participants. Gains and losses in excess of 10 percent of the greater of the benefit obligation and the market-related value of assets are amortized over the average remaining service period of active participants.

Note 9 - Earnings per Share

Basic net income or loss per common share is calculated by dividing net income or loss available to common stockholders by the basic weighted-average common shares outstanding for the respective period. The Company’s earnings per share calculations reflect the impact of any repurchases of shares of common stock made by the Company.

Diluted net income or loss per common share is calculated by dividing adjusted net income or loss by the diluted weighted-average common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for this calculation consist of unvested RSUs, contingent PSUs, and in-the-money outstanding stock options. The treasury stock method is used to measure the dilutive impact of these stock awards. All remaining stock options were exercised during the year ended December 31, 2014, and therefore, were only dilutive for the three months ended March 31, 2014. When there is a loss from continuing operations, as was the case for the three months ended March 31, 2015, all potentially dilutive shares are anti-dilutive and are consequently excluded from the calculation of diluted net loss per common share. For the three months ended March 31, 2015, weighted-average anti-dilutive securities related to unvested RSUs and contingent PSUs totaled approximately 452,000 shares.

PSUs represent the right to receive, upon settlement of the PSUs after completion of the three-year performance period, a number of shares of the Company’s common stock that may range from 0% to 200% of the number of PSUs granted on the award date. The number of potentially dilutive shares related to PSUs is based on the number of shares, if any, that would be issuable at the end of the respective reporting period, assuming that date was the end of the contingency period applicable to such PSUs. For additional discussion on PSUs, please refer to Note 7 - Compensation Plans under the heading Performance Share Units Under the Equity Incentive Compensation Plan.

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The following table sets forth the calculations of basic and diluted earnings per share:

	For the Three Months Ended March 31,	
	2015	2014
	(in thousands, except per share amounts)	
Net income (loss)	$(53,058)	$65,607
Basic weighted-average common shares outstanding	67,463	67,056
Add: dilutive effect of stock options, unvested RSUs, and contingent PSUs	—	1,070
Diluted weighted-average common shares outstanding	67,463	68,126
Basic net income (loss) per common share	$(0.79)	$0.98
Diluted net income (loss) per common share	$(0.79)	$0.96

Note 10 - Derivative Financial Instruments

Summary of Oil, Gas, and NGL Derivative Contracts in Place

The Company has entered into various commodity derivative contracts to mitigate a portion of its exposure to potentially adverse market changes in commodity prices and the associated impact on cash flows. All contracts are entered into for other-than-trading purposes. The Company's derivative contracts include swap and collar arrangements for oil, gas, and NGLs.

As of March 31, 2015, the Company had commodity derivative contracts outstanding through the fourth quarter of 2019 for a total of 12.1 million Bbls of oil production, 204.7 million MMBtu of gas production, and 1.5 million Bbls of NGL production. Subsequent to March 31, 2015, the Company entered into derivative contracts through the second quarter of 2018 for a total of 387,000 Bbls of NGL production with contract prices ranging from $9.66 per Bbl to $10.19 per Bbl. These subsequent derivative contracts for ethane production are based on Oil Price Information Service ("OPIS") Purity Ethane Mont Belvieu pricing.

In a typical commodity swap agreement, if the agreed upon published third-party index price ("index price") is lower than the swap fixed price, the Company receives the difference between the index price and the agreed upon swap fixed price. If the index price is higher than the swap fixed price, the Company pays the difference. For collar agreements, the Company receives the difference between an index price and the floor price if the index price is below the floor price. The Company pays the difference between the ceiling price and the index price if the index price is above the ceiling price. No amounts are paid or received if the index price is between the floor and ceiling prices.

The following tables summarize the approximate volumes and average contract prices of contracts the Company had in place as of March 31, 2015:

Oil Contracts

Oil Swaps

Contract Period	NYMEX WTI Volumes	Weighted-Average Contract Price
	(Bbls)	(per Bbl)
Second quarter 2015	1,639,000	$91.26
Third quarter 2015	1,254,000	$90.78
Fourth quarter 2015	1,137,000	$90.15
2016	5,570,000	$88.01
All oil swaps	9,600,000	

Oil Collars

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(Bbls)	(per Bbl)	(per Bbl)
Second quarter 2015	709,000	$85.00	$94.06
Third quarter 2015	906,000	$85.00	$91.25
Fourth quarter 2015	869,000	$85.00	$92.19
All oil collars	2,484,000		

Gas Contracts

Gas Swaps

Contract Period	Volumes	Weighted-Average Contract Price
	(MMBtu)	(per MMBtu)
Second quarter 2015	15,985,000	$3.90
Third quarter 2015	14,950,000	$4.03
Fourth quarter 2015	13,570,000	$4.02
2016	48,896,000	$4.12
2017	37,414,000	$4.16
2018	35,241,000	$4.21
2019	28,159,000	$4.28
All gas swaps*	194,215,000	

*Gas swaps are comprised of IF El Paso Permian (2%), IF HSC (83%), IF NGPL TXOK (1%), IF NNG Ventura (3%), and IF Enable East (11%).

Gas Collars

Contract Period	Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(MMBtu)	(per MMBtu)	(per MMBtu)
Second quarter 2015	2,297,000	$4.00	$4.30
Third quarter 2015	2,005,000	$4.00	$4.30
Fourth quarter 2015	6,176,000	$3.97	$4.30
All gas collars*	10,478,000		

*Gas collars are comprised of IF El Paso Permian (4%), IF HSC (79%), IF NNG Ventura (7%), and IF Enable East (10%).

NGL Contracts

NGL Swaps

Contract Period	OPIS Purity Ethane Mt Belv. Volumes (Bbls)	Weighted-Average Contract Price (per Bbl)
2016	710,000	$9.12
2017	542,000	$10.13
2018	210,000	$10.74
All NGL swaps	1,462,000	

Derivative Assets and Liabilities Fair Value

The Company's commodity derivatives are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities. The fair value of the commodity derivative contracts was a net asset of $585.1 million and net asset of $592.1 million as of March 31, 2015, and December 31, 2014, respectively.

The following tables detail the fair value of derivatives recorded in the accompanying balance sheets, by category:

	As of March 31, 2015			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity contracts	Current assets	$380,633	Current liabilities	$—
Commodity contracts	Noncurrent assets	204,841	Noncurrent liabilities	398
Derivatives not designated as hedging instruments		$585,474		$398

	As of December 31, 2014			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity contracts	Current assets	$402,668	Current liabilities	$—
Commodity contracts	Noncurrent assets	189,540	Noncurrent liabilities	70
Derivatives not designated as hedging instruments		$592,208		$70

Offsetting of Derivative Assets and Liabilities

As of March 31, 2015, and December 31, 2014, all derivative instruments held by the Company were subject to enforceable master netting arrangements by various financial institutions. In general, the terms of the Company's agreements provide for offsetting of amounts payable or receivable between it and the counterparty, at the election of both parties, for transactions that occur on the same date and in the same currency. The Company's agreements also provide that in the event of an early termination, the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. The Company's accounting policy is to not offset these positions in its accompanying balance sheets.

The following table provides a reconciliation between the gross assets and liabilities reflected on the accompanying balance sheets and the potential effects of master netting arrangements on the fair value of the Company’s derivative contracts:

Offsetting of Derivative Assets and Liabilities	Derivative Assets As of March 31, 2015	December 31, 2014	Derivative Liabilities As of March 31, 2015	December 31, 2014
	(in thousands)			
Gross amounts presented in the accompanying balance sheets	$585,474	$592,208	$(398)	$(70)
Amounts not offset in the accompanying balance sheets	(398)	(70)	398	70
Net amounts	$585,076	$592,138	$—	$—

The following table summarizes the components of the derivative (gain) loss presented in the accompanying statements of operations:

	For the Three Months Ended March 31, 2015	2014
	(in thousands)	
Derivative settlement (gain) loss:		
Oil contracts	$(106,214)	$6,758
Gas contracts	(34,232)	13,404
NGL contracts	(20,783)	8,778
Total derivative settlement (gain) loss [1]	$(161,229)	$28,940
Total derivative (gain) loss:		
Oil contracts	$(73,860)	$31,950
Gas contracts	(82,339)	59,461
NGL contracts	2,032	6,251
Total derivative (gain) loss [2]	$(154,167)	$97,662

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(1) Total derivative settlement (gain) loss is reported net of the change in accrued settlements between periods in the derivative cash settlements line item on the condensed consolidated statements of cash flows within net cash provided by operating activities.

(2) Total derivative (gain) loss is reported in the derivative (gain) loss line item on the condensed consolidated statements of cash flows within net cash provided by operating activities.

Credit Related Contingent Features

As of March 31, 2015, and through the filing date of this report, all of the Company’s derivative counterparties were members of the Company’s credit facility lender group. The Company’s obligations under its derivative contracts are secured by mortgages on assets having a value equal to at least 75 percent of the total value of the Company’s proved oil and gas properties.

Note 11 - Fair Value Measurements

The Company follows fair value measurement authoritative accounting guidance for all assets and liabilities measured at fair value. This guidance defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Market or observable inputs are the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The fair value hierarchy for grouping these assets and liabilities is based on the significance level of the following inputs:

- Level 1 – quoted prices in active markets for identical assets or liabilities
- Level 2 – quoted prices in active markets for similar assets or liabilities, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations whose inputs are observable or whose significant value drivers are observable
- Level 3 – significant inputs to the valuation model are unobservable

The following table is a listing of the Company's assets and liabilities that are measured at fair value and where they are classified within the fair value hierarchy as of March 31, 2015:

	Level 1 (in thousands)	Level 2	Level 3
Assets:			
Derivatives [1]	$—	$585,474	$—
Proved oil and gas properties [2]	$—	$—	$48,969
Oil, gas, and other property and equipment held for sale [2]	$—	$—	$58,779
Liabilities:			
Derivatives [1]	$—	$398	$—
Net Profits Plan [1]	$—	$—	$22,802
Asset retirement obligation associated with oil and gas properties held for sale [2]	$—	$—	$9,509

(1) This represents a financial asset or liability that is measured at fair value on a recurring basis.
(2) This represents a non-financial asset or liability that is measured at fair value on a nonrecurring basis.

The following is a listing of the Company's assets and liabilities that are measured at fair value and where they were classified within the hierarchy as of December 31, 2014:

	Level 1 (in thousands)	Level 2	Level 3
Assets:			
Derivatives [1]	$—	$592,208	$—
Proved oil and gas properties [2]	$—	$—	$33,423
Oil, gas, and other property and equipment held for sale [2]	$—	$—	$17,891
Liabilities:			
Derivatives [1]	$—	$70	$—
Net Profits Plan [1]	$—	$—	$27,136

(1) This represents a financial asset or liability that is measured at fair value on a recurring basis.
(2) This represents a non-financial asset that is measured at fair value on a nonrecurring basis.

Both financial and non-financial assets and liabilities are categorized within the above fair value hierarchy based on the lowest level of input that is significant to the fair value measurement. The following is a description of the valuation methodologies used by the Company as well as the general classification of such instruments pursuant to the above fair value hierarchy.

Derivatives

The Company uses Level 2 inputs to measure the fair value of oil, gas, and NGL commodity derivatives. Fair values are based upon interpolated data. The Company derives internal valuation estimates taking into consideration forward commodity price curves, counterparties' credit ratings, the Company's credit rating, and the time value of money. These valuations are then compared to the respective counterparties' mark-to-market statements. The considered factors result in an estimated exit-price that management believes provides a reasonable and consistent methodology for valuing derivative instruments. The derivative instruments utilized by the Company are not considered by management to be complex, structured, or illiquid. The oil, gas, and NGL commodity derivative markets are highly active.

Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. However, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. The Company monitors the credit ratings of its counterparties and may require counterparties to post collateral if their ratings deteriorate. In some instances, the Company will attempt to novate the trade to a more stable counterparty.

Valuation adjustments are necessary to reflect the effect of the Company's credit quality on the fair value of any derivative liability position. This adjustment takes into account any credit enhancements, such as collateral margin that the Company may have posted with a counterparty, as well as any letters of credit between the parties. The methodology to determine this adjustment is consistent with how the Company evaluates counterparty credit risk, taking into account the Company's credit rating, current credit facility margins, and any change in such margins since the last measurement date. All of the Company's derivative counterparties are members of the Company's credit facility lender group.

The methods described above may result in a fair value estimate that may not be indicative of net realizable value or may not be reflective of future fair values and cash flows. While the Company believes that the valuation methods utilized are appropriate and consistent with authoritative accounting guidance and with other marketplace participants, the Company recognizes that third parties may use different methodologies or assumptions to determine the fair value of certain financial instruments that could result in a different estimate of fair value at the reporting date.

Refer to Note 10 - Derivative Financial Instruments for more information regarding the Company's derivative instruments.

Net Profits Plan

The Net Profits Plan is a standalone liability for which there is no available market price, principal market, or market participants. The inputs available for this instrument are unobservable and are therefore classified as Level 3 inputs. The Company employs the income valuation technique, which converts expected future cash flow amounts to a single present value amount. This technique uses the estimate of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk to calculate the fair value. There is a direct correlation between realized oil, gas, and NGL commodity prices driving net cash flows and the Net Profits Plan liability. Generally, higher commodity prices result in a larger Net Profits Plan liability and lower commodity prices result in a smaller Net Profits Plan liability.

The Company records the estimated fair value of the long-term liability for estimated future payments under the Net Profits Plan based on the discounted value of estimated future payments associated with each individual pool. The calculation of this liability is a significant management estimate. A discount rate of 12 percent is used to calculate this liability and is intended to represent the Company's best estimate of the present value of expected future payments under the Net Profits Plan.

The Company's estimate of its liability is highly dependent on commodity prices, cost assumptions, discount rates, and overall market conditions. The Company regularly assesses the current market environment. The Net Profits Plan liability is determined using price assumptions of five one-year strip prices with the fifth year's pricing then carried out indefinitely. The average price is adjusted for realized price differentials and to include the effects of the forecasted production covered by derivative contracts in the relevant periods. The non-cash expense associated with this significant management estimate is highly volatile from period to period due to fluctuations that occur in the oil, gas, and NGL commodity markets.

If the commodity prices used in the calculation changed by five percent, the liability recorded at March 31, 2015, would differ by approximately $2 million. A one percent increase or decrease in the discount rate would result in a change of approximately $1 million. Actual cash payments to be made to participants in future periods are dependent on realized actual production, realized commodity prices, and costs associated with the properties in each individual pool of the Net Profits Plan. Consequently, actual cash payments are inherently different from the amounts estimated.

No published market quotes exist on which to base the Company's estimate of fair value of its Net Profits Plan liability. As such, the recorded fair value is based entirely on management estimates that are described within this footnote. While some inputs to the Company's calculation of fair value of the Net Profits Plan's future payments are from published sources, others, such as the discount rate and the expected future cash flows, are derived from the Company's own calculations and estimates.

The following table reflects the activity for the Company's Net Profits Plan liability measured at fair value using Level 3 inputs:

	For the Three Months Ended March 31, 2015	
	(in thousands)	
Beginning balance	$27,136	
Net decrease in liability [1]	(3,035	)
Net settlements [1] [2]	(1,299	)
Transfers in (out) of Level 3	—	
Ending balance	$22,802	

(1) Net changes in the Company's Net Profits Plan liability are shown in the Change in Net Profits Plan liability line item of the accompanying statements of operations.

(2) Settlements represent cash payments made or accrued under the Net Profits Plan.

Long-term Debt

The following table reflects the fair value of the Senior Notes measured using Level 1 inputs based on quoted secondary market trading prices. The Senior Notes were not presented at fair value on the accompanying balance sheets as of March 31, 2015, or December 31, 2014, as they are recorded at historical value.

	As of March 31, 2015	As of December 31, 2014
	(in thousands)	
2019 Notes	$359,730	$350,018
2021 Notes	$357,438	$343,000
2022 Notes	$601,878	$556,500
2023 Notes	$408,080	$379,000
2024 Notes	$472,500	$435,000

The carrying value of the Company's credit facility approximates its fair value, as the applicable interest rates are floating, based on prevailing market rates.

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Proved and Unproved Oil and Gas Properties

Proved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication the carrying costs may not be recoverable. The Company uses Level 3 inputs and the income valuation technique, which converts future amounts to a single present value amount, to measure the fair value of proved properties through an application of discount rates and price forecasts selected by the Company's management. The calculation of the discount rate is based on the best information available and was estimated to be 12 percent as of March 31, 2015, and December 31, 2014. The Company believes the discount rate is representative of current market conditions and takes into account estimates of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk. The prices for oil and gas are forecast based on New York Mercantile Exchange ("NYMEX") strip pricing, adjusted for basis differentials, for the first five years, after which a flat terminal price is used for each commodity stream. The prices for NGLs are forecast using OPIS Mont Belvieu pricing, for as long as the market is actively trading, after which a flat terminal price is used. Future operating costs are also adjusted as deemed appropriate for these estimates. The Company recorded impairment of proved oil and gas properties of $55.5 million for the three months ended March 31, 2015, due to continued declines in commodity strip prices since year-end 2014, and the Company's decision to reduce capital invested in the development of certain prospects in its South Texas & Gulf Coast and Permian regions. Proved properties measured at fair value within the accompanying balance sheets totaled $49.0 million as of March 31, 2015. As of December 31, 2014, proved oil and gas properties measured at fair value totaled $33.4 million.

Proved properties classified as held for sale, including the corresponding asset retirement obligation liability, are valued using a market approach, based on an estimated selling price, as evidenced by the most current bid prices received from third parties, if available. If an estimated selling price is not available, the Company utilizes the income valuation technique discussed above. For the three months ended March 31, 2015, the Company recorded write-downs to fair value less estimated costs to sell of $30.0 million for certain assets held for sale in its Mid-Continent region. Please refer to Note 3 - Assets Held for Sale.

Unproved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. To measure the fair value of unproved properties, the Company uses a market approach, which takes into account the following significant assumptions: future development plans, risk weighted potential resource recovery, and estimated reserve values. Unproved properties classified as held for sale are valued using a market approach, based on an estimated selling price, as evidenced by the most current bid prices received from third parties. If an estimated selling price is not available, the Company estimates acreage value based on the price received for similar acreage in recent transactions by the Company or other market participants in the principal market. The Company recorded abandonment and impairment of unproved oil and gas properties of $11.6 million for the three months ended March 31, 2015, related to acreage the Company no longer intended to develop. Unproved properties measured at fair value were written down to zero in the accompanying balance sheets as of March 31, 2015. As of December 31, 2014, unproved properties measured at fair value were also written down to zero.

The fair value measurements of assets acquired and liabilities assumed are measured on a nonrecurring basis on the acquisition date using an income valuation technique based on inputs that are not observable in the market and therefore represent Level 3 inputs. Significant inputs to the valuation of acquired oil and gas properties include estimates of: (i) reserves; (ii) production rates; (iii) future operating and development costs; (iv) future commodity prices, including price differentials; (v) future cash flows; and (vi) a market participant-based weighted average cost of capital rate. These inputs require significant judgments and estimates by the Company's management at the time of the valuation.

Note 12 - Suspended Well Costs

During the three-month period ended March 31, 2015, $15.1 million of capitalized exploratory well costs as of December 31, 2014, were charged to expense. These costs were related to a well, for which none of the costs were capitalized for a period greater than one year as of December 31, 2014, or at the time the well was determined to be unsuccessful.

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

This discussion and analysis contains forward-looking statements. Refer to Cautionary Information about Forward-Looking Statements at the end of this item for an explanation of these types of statements.

Overview of the Company, Highlights, and Outlook

General Overview

We are an independent energy company engaged in the acquisition, exploration, development, and production of oil, gas, and NGLs in onshore North America. We have leading positions in the Eagle Ford shale and Bakken/Three Forks resource plays that are the focus of our development programs. We also have smaller delineation and exploration programs in the Powder River Basin, the Permian Basin, and in east Texas. We have built a portfolio of onshore properties primarily through early entry into existing and emerging resource plays. This portfolio is comprised of properties with established production and reserves, prospective drilling opportunities, and unconventional resource prospects. We believe our strategy provides for stable and predictable production and reserves growth.

Our strategic objective is to build our ownership and operatorship of North American oil, gas and NGL producing assets that have high operating margins and significant opportunities for additional economic investment. We pursue opportunities through both acquisitions and exploration, and seek to maximize the value of our assets through industry leading technology application and outstanding operational execution. We are returns focused and maintain a simple, strong balance sheet through a conservative approach to leverage.

In the first quarter of 2015, we had the following financial and operational results:

- Average net daily production for the three months ended March 31, 2015, was 58.1 MBbls of oil, 510.3 MMcf of gas, and 43.3 MBbls of NGLs, for a record quarterly equivalent daily production rate of 186.4 MBOE, compared with 138.6 MBOE for the same period in 2014. Please see additional discussion below under Production Results.

- We recorded a net loss of $53.1 million, or $0.79 per diluted share, for the three months ended March 31, 2015, compared to net income for the three months ended March 31, 2014, of $65.6 million, or $0.96 per diluted share. Please refer to the Comparison of Financial Results and Trends Between the Three Months Ended March 31, 2015, and 2014 below for additional discussion regarding the components of net income (loss).

- Costs incurred for oil and gas property acquisitions and exploration and development activities for the three months ended March 31, 2015, totaled $499.7 million. The majority of our drilling and completion costs incurred during this period were in our Eagle Ford shale and Bakken/Three Forks programs. Total costs incurred for the same period in 2014 were $346.7 million. Please refer to Overview of Liquidity and Capital Resources below for additional discussion on how we expect to fund our capital program.

- Adjusted EBITDAX, a non-GAAP financial measure, for the three months ended March 31, 2015, was $311.9 million, compared to $398.9 million for the same period in 2014. Please refer to Non-GAAP Financial Measures below for additional discussion, including our definition of adjusted EBITDAX and reconciliations of our GAAP net income (loss) and net cash provided by operating activities to adjusted EBITDAX.

Oil, Gas, and NGL Prices

Our financial condition and the results of our operations are significantly affected by the prices we receive for our oil, gas, and NGL production, which can fluctuate dramatically. We sell the majority of our gas under contracts using first-of-the-month index pricing, which means gas produced in a given month is sold at the first-of-the-month price regardless of the spot price on the day the gas is produced. For assets where high BTU gas is sold at the wellhead, we also receive additional value for the higher energy content contained in the gas stream. Our NGL production is generally sold using contracts paying us a monthly average of the posted OPIS daily settlement prices, adjusted for processing, transportation, and location differentials. Our oil is sold using contracts paying us various industry posted prices, adjusted for basis differentials. We are paid the average of the daily settlement price for the respective posted prices for the period in which the product is sold, adjusted for quality, transportation, American Petroleum Institute ("API") gravity, and location differentials. When we refer to realized oil, gas, and NGL prices below, the disclosed price represents the average price for the respective period, before the effects of derivative settlements, unless otherwise indicated.

The following table summarizes commodity price data, as well as the effects of derivative settlements, for the first quarter of 2015, as well as the fourth and first quarters of 2014:

	For the Three Months Ended		
	March 31, 2015	December 31, 2014	March 31, 2014
Crude Oil (per Bbl):			
Average daily NYMEX price	$48.49	$73.21	$98.65
Realized price, before the effects of derivative settlements	$38.56	$62.60	$88.96
Effects of derivative settlements	$20.33	$10.95	$(1.85)
Natural Gas:			
Average daily NYMEX price (per MMBtu)	$2.87	$3.75	$5.16
Realized price, before the effects of derivative settlements (per Mcf)	$2.76	$3.87	$5.22
Effects of derivative settlements (per Mcf)	$0.75	$0.04	$(0.38)
Natural Gas Liquids (per Bbl):			
Average daily OPIS price	$21.53	$29.53	$45.61
Realized price, before the effects of derivative settlements	$16.67	$25.97	$38.79
Effects of derivative settlements	$5.33	$4.74	$(3.03)

Note: Average OPIS prices per barrel of NGL, historical or strip, are based on a product mix of 37% Ethane, 32% Propane, 6% Isobutane, 11% Normal Butane, and 14% Natural Gasoline for all periods presented. This product mix represents the industry standard composite barrel and does not necessarily represent our product mix for NGL production. Realized prices reflect our actual product mix.

While quoted NYMEX oil and gas and OPIS NGL prices are generally used as a basis for comparison within our industry, the prices we receive are affected by quality, energy content, location, and transportation differentials for these products.

We expect future prices for oil, gas, and NGLs to be volatile. In addition to supply and demand fundamentals, as a global commodity, the price of oil will continue to be impacted by real or perceived geopolitical risks in oil producing regions of the world, particularly the Middle East. The relative strength of the U.S. dollar compared to other currencies also could affect the price of oil. Lower forecasted levels of global economic growth combined with excess global supply have weighed on oil prices in recent months. This was exacerbated by the decision of the Organization of Petroleum Exporting Countries ("OPEC") not to cut production in November of 2014. In response to lower oil prices in recent months, industry participants have significantly cut capital spending, which we expect will result in lower supply. The prices of several NGL products generally correlate to the price of oil, and accordingly, prices for these products have fallen in recent months and are likely to continue to directionally follow that market. Gas prices have been under downward pressure recently due to higher levels of gas in storage compared to last year although storage levels remain lower than the 5-year average. Longer term, we anticipate natural gas prices will trade in a range higher than current price levels. Changes to existing laws and regulations pertaining to the ability to export oil, gas, and NGLs also have the potential to impact the prices for these commodities. The following table summarizes 12-month strip prices for NYMEX WTI oil, NYMEX Henry Hub gas, and OPIS NGLs (same product mix as discussed under the table above) as of April 29, 2015, and March 31, 2015:

	As of April 29, 2015	As of March 31, 2015
NYMEX WTI oil (per Bbl)	$61.82	$53.30
NYMEX Henry Hub gas (per MMBtu)	$2.89	$2.91
OPIS NGLs (per Bbl)	$23.76	$21.57

Derivative Activity

We use financial derivative instruments as part of our financial risk management program. We have a financial risk management policy governing our use of derivatives. The amount of our production covered by derivatives is driven by the amount of debt on our balance sheet and the level of capital commitments and long-term obligations we have in place. With our current derivative contracts, we believe we have established a base cash flow stream for our current year operations and have partially reduced our exposure to volatility in commodity prices in the near term. Our use of costless collars for a portion of our derivatives allows us to participate in some of the upward movements in oil and gas prices while also setting a price floor for a portion of our production. Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report for additional information regarding our oil, gas, and NGL derivatives.

The Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank Act") included provisions requiring over-the-counter derivative transactions to be cleared through clearinghouses and traded on exchanges. On July 10, 2012, the Commodity Futures Trading Commission ("CFTC") and the SEC adopted final joint rules under Title VII of the Dodd-Frank Act, which define certain terms that determine what types of transactions will be subject to regulation under the Dodd-Frank Act swap rules. The issuance of these final rules also triggers compliance dates for a number of other final Dodd-Frank Act rules, including new rules proposed by the CFTC governing margin requirements for uncleared swaps entered into by non-bank swap entities, and new rules proposed by U.S. banking regulators regarding margin requirements for uncleared swaps entered into by bank swap entities. The ultimate effect of these new rules on our business and any additional regulations is currently uncertain. Under CFTC rules we believe our derivative activity will qualify for the non-financial, commercial end-user exception, which exempts derivatives intended to hedge or mitigate commercial risk entered into by entities predominantly engaged in non-financial activity from the mandatory swap clearing requirement. However, we are not certain whether the provisions of the final rules and regulations will exempt us from the requirements to post margin in connection with commodity price risk management activities. Final rules and regulations on major provisions of the legislation, such as new margin requirements, are to be established through regulatory rulemaking. Although we cannot predict the ultimate outcome of these rulemakings, new rules and regulations in this area may result in increased costs and cash collateral requirements for the types of derivative instruments we use to manage our financial risks related to volatility in oil, gas, and NGL commodity prices.

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First Quarter 2015 Highlights and Outlook for the Remainder of 2015

Operational Activities. We view 2015 as a year of transition as the broader oil and gas industry adjusts to lower oil prices. Exploration and production companies are reducing drilling and completion activity, resulting in service companies lowering the price for their services. Our plan for 2015 is to scale back activity over the course of the year, while preserving the value of our assets and protecting the strength of our balance sheet. As part of this plan, we expect to defer completion of certain wells drilled during the year and to build our inventory of wells waiting on completion. Our goal is to be well positioned entering 2016 in what we expect will be a stronger commodity price and lower service cost environment, while having the strength and flexibility to adapt should industry conditions change.

We expect our capital program for 2015 to be approximately $1.2 billion, $1.0 billion of which we plan to invest in drilling and completion activities. We expect to focus between 80 and 85 percent of our drilling and completion capital on our core development programs in the Eagle Ford shale and the Bakken/Three Forks formations. We expect that annual production will increase in 2015 compared to 2014, while sequential quarterly production will decline throughout the year.

During the first quarter of 2015, we operated five drilling rigs in our operated Eagle Ford shale program in South Texas, and expect to reduce operated drilling activity to a four rig program for the second quarter of 2015. Last year, our development program shifted to utilizing longer laterals and completions with higher sand loadings. Results from these enhanced completion techniques suggest significantly improved well performance. We expect to continue testing the potential of the upper Eagle Ford interval throughout the year.

In our non-operated Eagle Ford shale program, the operator began 2015 running seven rigs and dropped to five rigs by the end of the first quarter. The operator has indicated it will continue to evaluate rig count as it pertains to contracts, drilling obligations, and changes in commodity prices.

In our Bakken/Three Forks program, we operated five drilling rigs during the first quarter of 2015, and expect to reduce operated drilling activity to a two rig program by year-end. We plan to focus most of our 2015 activity in Divide County, North Dakota to develop and delineate acreage we added in 2014. We are monitoring the results of various tests, including drilling and completion optimizations, and down-spacing of both our operated and non-operated properties in this area.

Given the current commodity price environment, we are scaling back activity in our delineation and exploration programs and certain development programs in 2015. We expect to reduce our activity in the Powder River Basin, the Permian Basin, and east Texas, while still focusing on preserving acreage positions.

In our Permian program, we started 2015 operating two drilling rigs, dropped one rig during the first quarter, and expect to drop the other rig during the second quarter. We have been focused on horizontal testing and development of the Wolfcamp and Spraberry intervals in and around our Sweetie Peck property in Upton County, Texas, and on testing various target intervals in our Buffalo prospect in Gaines and Dawson Counties, Texas.

In our Powder River Basin program in Wyoming, our focus has been on delineating our acreage position. We started 2015 operating four drilling rigs and dropped two rigs during the first quarter. We dropped another rig at the beginning of the second quarter of 2015 and plan to operate one rig for the remainder of the year.

We will continue to evaluate our rig count throughout the year and into next year as we respond to commodity price changes and reduced service provider costs. Please refer to Overview of Liquidity and Capital Resources below for additional discussion regarding how we intend to fund our 2015 capital program.

Production Results. The table below provides a regional breakdown of our production for the first quarter of 2015:

	South Texas & Gulf Coast		Rocky Mountain		Permian		Mid-Continent		Total [1]	
Oil (MMBbl)	2.3		2.3		0.6		—		5.2	
Gas (Bcf)	36.8		2.0		1.3		5.8		45.9	
NGLs (MMBbl)	3.8		0.1		—		—		3.9	
Equivalent (MMBOE)	12.3		2.7		0.8		1.0		16.8	
Avg. daily equivalents (MBOE/d)	136.5		30.1		8.7		11.1		186.4	
Relative percentage	73	%	16	%	5	%	6	%	100	%

[1] Amounts may not calculate due to rounding.

Production increased for the three months ended March 31, 2015, compared to the same period in 2014, driven primarily by the continued development of our operated and non-operated Eagle Ford shale programs in our South Texas & Gulf Coast region. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended March 31, 2015, and 2014 below for additional discussion on production.

Costs Incurred in Oil and Gas Producing Activities. Costs incurred in oil and gas property acquisition, exploration and development activities, whether capitalized or expensed, are summarized as follows:

	For the Three Months Ended March 31, 2015 (in millions)
Development costs [1]	$438.9
Exploration costs	46.2
Acquisitions	
Proved properties	8.9
Unproved properties	5.7
Total, including asset retirement obligations [2]	$499.7

[1] Includes facility costs of $31.7 million for the three months ended March 31, 2015.
[2] Includes amounts relating to estimated asset retirement obligations of $2.7 million and capitalized interest of $4.9 million for the three months ended March 31, 2015.

The majority of costs incurred for oil and gas producing activities during the first quarter of 2015 were on the development of our Eagle Ford shale and Bakken/Three Forks programs. Please refer to Overview of Liquidity and Capital Resources below for additional discussion on how we fund our capital program.

Subsequent Events. Subsequent to March 31, 2015, as a result of our regularly scheduled semi-annual borrowing base redetermination, our lenders reaffirmed our borrowing base under our credit facility at $2.4 billion.

Additionally, subsequent to March 31, 2015, we entered into purchase and sale agreements for the sale of our Mid-Continent assets that were classified as held for sale at March 31, 2015. Please refer to Note 3 - Assets Held for Sale in Part I, Item 1 of this report for additional discussion.

Financial Results of Operations and Additional Comparative Data

The tables below provide information regarding selected production and financial information. A detailed discussion follows.

	For the Three Months Ended			
	March 31, 2015	December 31, 2014	September 30, 2014	June 30, 2014
	(in millions, except for production data)			
Production (MMBOE)	16.8	16.2	13.1	13.4
Oil, gas, and NGL production revenue	$393.3	$586.6	$617.2	$654.7
Oil, gas, and NGL production expense	$196.2	$196.2	$178.4	$177.6
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$217.4	$219.3	$183.3	$187.8
Exploration	$37.4	$49.7	$34.6	$24.3
General and administrative	$43.6	$52.2	$41.7	$38.1
Net income (loss)	$(53.1)	$331.7	$208.9	$59.8

Note: Quarterly amounts may not calculate due to rounding.

Selected Performance Metrics:

	For the Three Months Ended			
	March 31, 2015	December 31, 2014	September 30, 2014	June 30, 2014
Average net daily production equivalent (MBOE/d)	186.4	175.8	142.5	147.0
Lease operating expense (per BOE)	$3.96	$4.29	$4.58	$4.17
Transportation costs (per BOE)	$6.08	$5.77	$6.22	$6.20
Production taxes as a percent of oil, gas, and NGL production revenue	4.8%	4.7%	4.9%	4.9%
Ad valorem tax expense (per BOE)	$0.52	$0.37	$0.49	$0.52
Depletion, depreciation, amortization, and asset retirement obligation liability accretion (per BOE)	$12.96	$13.56	$13.97	$14.03
General and administrative (per BOE)	$2.60	$3.23	$3.18	$2.85

Note: Amounts may not calculate due to rounding.

A three-month overview of selected production and financial information, including trends:

	For the Three Months Ended March 31,		Amount Change Between Periods	Percent Change Between Periods
	2015	2014		
Net production volumes [(1)]				
Oil (MMBbl)	5.2	3.7	1.6	43 %
Gas (Bcf)	45.9	35.5	10.4	29 %
NGLs (MMBbl)	3.9	2.9	1.0	35 %
Equivalent (MMBOE)	16.8	12.5	4.3	35 %
Average net daily production [(1)]				
Oil (MBbl per day)	58.1	40.6	17.4	43 %
Gas (MMcf per day)	510.3	394.9	115.4	29 %
NGLs (MBbl per day)	43.3	32.1	11.2	35 %
Equivalent (MBOE per day)	186.4	138.6	47.9	35 %
Oil, gas, and NGL production revenue (in millions)				
Oil production revenue	$201.5	$325.3	$(123.8)	(38)%
Gas production revenue	126.8	185.6	(58.8)	(32)%
NGL production revenue	65.0	112.2	(47.2)	(42)%
Total	$393.3	$623.1	$(229.8)	(37)%
Oil, gas, and NGL production expense (in millions)				
Lease operating expense	$66.5	$50.7	$15.8	31 %
Transportation costs	102.1	79.2	22.9	29 %
Production taxes	18.8	27.5	(8.7)	(32)%
Ad valorem tax expense	8.8	6.3	2.5	40 %
Total	$196.2	$163.7	$32.5	20 %
Realized price				
Oil (per Bbl)	$38.56	$88.96	$(50.40)	(57)%
Gas (per Mcf)	$2.76	$5.22	$(2.46)	(47)%
NGLs (per Bbl)	$16.67	$38.79	$(22.12)	(57)%
Per BOE	$23.44	$49.96	$(26.52)	(53)%
Per BOE Data [(1)]				
Production costs:				
Lease operating expense	$3.96	$4.07	$(0.11)	(3)%
Transportation costs	$6.08	$6.35	$(0.27)	(4)%
Production taxes	$1.12	$2.20	$(1.08)	(49)%
Ad valorem tax expense	$0.52	$0.51	$0.01	2 %
General and administrative	$2.60	$2.81	$(0.21)	(7)%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$12.96	$14.21	$(1.25)	(9)%
Derivative settlement gain (loss) [(2)]	$9.61	$(2.32)	$11.93	514 %
Earnings per share information				
Basic net income (loss) per common share	$(0.79)	$0.98	$(1.77)	(181)%
Diluted net income (loss) per common share	$(0.79)	$0.96	$(1.75)	(182)%
Basic weighted-average common shares outstanding (in thousands)	67,463	67,056	407	1 %
Diluted weighted-average common shares outstanding (in thousands)	67,463	68,126	(663)	(1)%

(1) Amount and percentage changes may not calculate due to rounding.
(2) Derivative settlements for the three months ended March 31, 2015, and 2014, are included within the derivative (gain) loss line item in the accompanying statements of operations.

We present per BOE information because we use this information to evaluate our performance relative to our peers and to identify and measure trends we believe may require additional analysis. Average daily production for the three months ended March 31, 2015, increased 35 percent compared with the same period in 2014, driven primarily by the continued development of our Eagle Ford shale and Bakken/Three Forks programs. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended March 31, 2015, and 2014 below for additional discussion.

Changes in production volumes, revenues, and costs reflect the highly volatile nature of our industry. Our realized price on a per BOE basis for the three months ended March 31, 2015, decreased 53 percent compared to the same period in 2014.

Lease operating expense ("LOE") on a per BOE basis for the three months ended March 31, 2015, decreased slightly compared to the same period in 2014. Our LOE is comprised of recurring LOE and workover expense. We experience volatility in our LOE as a result of seasonality in workover expense and the impact industry activity has on service provider costs. While we expect service provider costs to decrease in 2015 in response to reduced activity resulting from the weak commodity price environment, we expect LOE on a per BOE basis to be flat or slightly higher for the year. This results from a more active workover program in 2015, as well as declining quarterly production bearing the fixed cost components of our recurring LOE.

Transportation costs on a per BOE basis for the three months ended March 31, 2015, decreased four percent compared to the same period in 2014 due to lower trucking costs and deficiency fees recorded in the first quarter of 2015. Our Eagle Ford shale program has meaningfully higher transportation expense per unit of production compared to our other regions. Ongoing development of the Eagle Ford shale program has resulted in production from these assets becoming a larger portion of our total production, thereby increasing company-wide transportation expense per BOE over time. We expect this trend to continue, resulting in an increase in transportation costs on a per BOE basis for full-year 2015 as compared to full-year 2014.

Production taxes on a per BOE basis for the three months ended March 31, 2015, decreased 49 percent, in line with the decrease in production revenues, compared to the same period in 2014. We generally expect absolute production tax expense to trend with oil, gas, and NGL production revenue. Product mix, the location of production, and incentives to encourage oil and gas development can all impact or change the amount of production tax we recognize.

Ad valorem tax expense on a per BOE basis for the three months ended March 31, 2015, increased slightly compared to the same period in 2014. We expect ad valorem tax expense to fluctuate throughout the year on an absolute and on a per BOE basis as valuations are finalized. We also expect ad valorem tax expense to trend with proved reserve values determined as of the end of each prior year.

G&A expense on a per BOE basis for the three months ended March 31, 2015, decreased seven percent compared to the same period in 2014, as production increased at a faster rate than our general and administrative expense. A portion of our general and administrative expense is linked to our profitability and cash flow, which are driven in large part by the realized commodity prices we receive for our production. A portion of our short-term incentive compensation correlates with net cash flows and therefore is subject to variability. We expect G&A expense to increase year over year. This, as well as the expected decline in production over the next several quarters in 2015, will result in an increase in G&A expense on a per BOE basis for full-year 2015 as compared to full-year 2014. Please refer to Note 3 - Assets Held for Sale in Part I, Item 1 of this report for discussion on the expected exit and disposal costs to be incurred in 2015 relating to the closure of our Tulsa office.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion ("DD&A") expense on a per BOE basis for the three months ended March 31, 2015, decreased nine percent compared to the same period in 2014. Our DD&A rate can fluctuate as a result of impairments, planned and closed divestitures, and changes in the mix of our production and the underlying proved reserve volumes. Our DD&A rate has decreased as assets with lower finding and development costs have become a larger portion of our total production mix. Our finding and development costs have benefited from a general decrease in well costs and an increase in recoveries per well, as well as from our outside-operated Eagle Ford shale program, where, throughout the first half of 2014 and several years prior to 2014, we added reserves with minimal associated costs due to our carry with Mitsui E&P Texas LP under our Acquisition and Development Agreement. This carry was exhausted during the second quarter of 2014. We expect our DD&A rate to increase in future periods as we now record our full share of costs in our outside-operated Eagle Ford shale program. We expect the increase to be partially offset by the anticipated decrease in service provider costs in response to reduced activity resulting from the current lower commodity price environment. Additionally, during the first quarter of 2015, we began marketing for sale all of our Mid-Continent assets, which decreased DD&A on a per BOE basis, as these assets were held for sale, and therefore, no DD&A expense was recorded for these assets for the majority of the first quarter of 2015.

Please refer to Comparison of Financial Results and Trends Between the Three Months Ended March 31, 2015, and 2014 below for additional discussion on operating expenses.

Please refer to Note 9 - Earnings per Share in Part I, Item 1 of this report for discussion on the types of shares included in our basic and diluted net income (loss) per common share calculations.

Comparison of Financial Results and Trends Between the Three Months Ended March 31, 2015, and 2014

Oil, gas, and NGL production, revenue, and costs. The following table presents the regional changes in our oil, gas, and NGL production, revenue, and costs between the three months ended March 31, 2015, and 2014:

	Average Net Daily Production Increase (MBOE/d)	Oil, Gas, & NGL Production Revenue Decrease (in millions)	Production Costs Increase (Decrease) (in millions)
South Texas & Gulf Coast	34.9	$(138.3)	$30.1
Rocky Mountain	9.1	(62.7)	2.7
Permian	1.9	(19.4)	1.6
Mid-Continent	2.0	(9.4)	(1.9)
Total	47.9	$(229.8)	$32.5

A 35 percent increase in equivalent production combined with a 53 percent decrease in realized prices on a per BOE basis resulted in a 37 percent decrease in oil, gas, and NGL production revenue between the two periods. Please refer to A three-month overview of selected production and financial information, including trends above for realized prices received before the effects of derivative settlements for the three months ended March 31, 2015, and 2014. Overall, we anticipate an increase in production in 2015 from 2014 based on our forecasted drilling plan; however, we expect quarterly production to decline throughout 2015. We expect our realized prices to trend with commodity prices.

Gain (loss) on divestiture activity. We recorded a loss on divestiture activity of $35.8 million for the three months ended March 31, 2015, due largely to the write-down to fair value of certain assets held for sale in our Mid-Continent region. We recorded a gain on divestiture activity of $3.0 million for the same period in 2014. Please refer to Note 3 - Assets Held for Sale in Part I, Item 1 of this report for additional discussion.

Other operating revenues. Other operating revenues consist primarily of marketed gas system revenues. The increase for the three months ended March 31, 2015, compared to the same period in 2014, is driven by an increase in marketed gas volumes partially offset by a decrease in natural gas prices.

Oil, gas, and NGL production expense. Total production costs increased 20 percent for the three months ended March 31, 2015, compared with the same period of 2014, as a result of a 35 percent increase in net equivalent production volumes driving both recurring LOE and transportation costs higher, partially offset by a decrease in production taxes as a result of lower commodity prices. Please refer to A three-month overview of selected production and financial information, including trends above for discussion of production costs on a per BOE basis.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A expense increased 23 percent for the three-month period ended March 31, 2015, compared with the same period in 2014. Please refer to A three-month overview of selected production and financial information, including trends above for discussion of DD&A on a per BOE basis.

Exploration. The components of exploration expense are summarized as follows:

	For the Three Months Ended March 31,	
	2015	2014
	(in millions)	

Geological and geophysical expenses	$3.7	$4.1
Exploratory dry hole	16.3	—
Overhead and other expenses	17.4	17.2
Total	$37.4	$21.3

Exploration expense for the three months ended March 31, 2015, increased 75 percent compared to the same period in 2014, due to expensing an exploratory dry hole in our Rocky Mountain region in the first quarter of 2015. An exploratory project

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resulting in non-commercial quantities of oil, gas, or NGLs is deemed an exploratory dry hole and impacts the amount of exploration expense we record.

Impairment of proved properties. We recorded $55.5 million of impairment of proved properties expense for the three months ended March 31, 2015, due to further decline in commodity strip prices since year-end 2014, and our decision to reduce capital invested in the development of certain prospects in our South Texas & Gulf Coast and Permian regions. We recorded no impairment of proved properties in the first quarter of 2014. We expect impairments of proved properties to be more likely to occur in periods of declining commodity prices.

Abandonment and impairment of unproved properties. We recorded $11.6 million of abandonment and impairment of unproved properties expense for the three months ended March 31, 2015, compared to $2.8 million of expense recorded in the same period of 2014, related to acreage we no longer intended to develop. We expect our abandonment and impairment of unproved properties expense to fluctuate with the timing of lease expirations and unsuccessful exploration activities.

General and administrative. G&A expense increased 25 percent for the three months ended March 31, 2015, compared with the same period of 2014. The increase is due to an increase in employee headcount, which increased base and equity compensation, benefits, and general corporate office expenses, as well as approximately $3.2 million of exit and disposal costs recorded during the first quarter of 2015 related to the closure of our Tulsa office. Please refer to A three-month overview of selected production and financial information, including trends above for discussion of G&A expense on a per BOE basis.

Change in Net Profits Plan liability. This non-cash expense (benefit) generally relates to the change in the estimated value of the associated liability between the reporting periods. For the three months ended March 31, 2015, and 2014, we recorded a non-cash benefit of $4.3 million and $1.8 million, respectively. We generally expect the change in our Net Profits Plan liability to correlate with fluctuations in commodity prices.

Derivative (gain) loss. We recognized a derivative gain of $154.2 million for the three-month period ended March 31, 2015, driven by an increase in the fair value of commodity derivative contracts during the period resulting from a decline in strip pricing during the period. This compares to a derivative loss of $97.7 million for the same period in 2014, resulting from a decrease in the fair value of commodity derivative contracts during the period due to an increase in strip prices during the period. Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report for additional information.

Other operating expenses. For the three months ended March 31, 2015, and 2014, we recorded other operating expenses of $17.1 million and $8.1 million, respectively. The increase is primarily due to $3.2 million of expense related to the early termination of drilling rig contracts, as well as a $1.5 million materials inventory write-down during the first quarter of 2015. Other operating expenses also includes marketed gas system expense, which increased $2.7 million for the three months ended March 31, 2015, compared to the same period in 2014, driven by an increase in marketed gas volumes.

Income tax expense (benefit). We recorded income tax benefit of $33.5 million for the three-month period ended March 31, 2015, compared to expense of $38.9 million for the same period in 2014, resulting in effective tax rates of 38.7 percent and 37.2 percent, respectively. The higher effective tax rate resulted from finalizing a claimed R&D credit in 2015 partially offset by state apportionment factor changes between periods. Please refer to Note 4 - Income Taxes for additional discussion.

Overview of Liquidity and Capital Resources

We believe we have sufficient liquidity and capital resources to execute our business plan for the foreseeable future. We continue to manage the duration and level of our drilling and completion service commitments to maintain the flexibility to adjust our activity and capital expenditures in periods of prolonged weak commodity prices.

Sources of Cash

We currently expect our 2015 capital program to be funded by cash flows from operations and proceeds from planned divestitures, supplemented by borrowings under our credit facility. Although we anticipate cash flows from these sources will be sufficient to fund our expected 2015 capital program, we may also elect to access the capital markets, depending on prevailing market conditions, as well as divest of additional non-strategic oil and gas properties to provide additional sources of funding. From time to time, we may enter into carrying cost funding and sharing arrangements with third parties for particular exploration and/or development programs. All of our sources of liquidity can be impacted by the general condition of the broader economy and by fluctuations in commodity prices, operating costs, and volumes produced, all of which affect us and our industry. We have no control over the market prices for oil, gas, or NGLs, although we are able to influence the amount of our realized revenues from our oil, gas, and NGL sales through the use of derivative contracts as part of our commodity price risk management program. Historically, decreases in commodity prices have limited our industry's access to capital markets. The borrowing base under our credit facility could be reduced as a result of lower commodity prices, divestitures of proved properties, or newly issued debt. See Credit Facility below for a discussion of our most recent borrowing base redetermination.

Proposals to reform the Internal Revenue Code ("IRC"), which include eliminating or reducing current tax deductions for intangible drilling costs, depreciation of equipment acquisition costs, the domestic production activities deduction, percentage depletion, and other deductions which reduce our taxable income, continue to circulate. We expect that future legislation modifying or eliminating these deductions would reduce net operating cash flows over time, thereby reducing funding available for our exploration and development capital programs, as well as funding available to our peers in the industry for similar programs. If enacted, these reductions in available deductions could have a significant adverse effect on drilling in the United States for a number of years.

Credit Facility

Our credit facility has a maximum loan amount of $2.5 billion, current aggregate lender commitments of $1.5 billion, and a maturity date of December 10, 2019. The borrowing base is subject to regular semi-annual redeterminations and was reaffirmed on April 6, 2015, at $2.4 billion. We believe the current commitment amount is sufficient to meet our anticipated liquidity and operating needs. No individual bank participating in our credit facility represents more than 10 percent of the lending commitments under the credit facility. Borrowings under our credit facility are secured by mortgages on assets having a value equal to at least 75 percent of the total value of our proved oil and gas properties. Please refer to Note 5 - Long-term Debt in Part I, Item 1 of this report for additional discussion as well as the presentation of the outstanding balance, total amount of letters of credit, and available borrowing capacity under our credit facility as of April 29, 2015, March 31, 2015, and December 31, 2014.

We are subject to customary covenants under our credit facility, including limitations on dividend payments and requirements to maintain certain financial ratios, which include debt to adjusted EBITDAX, as defined by our credit agreement as the ratio of debt to 12-month trailing adjusted EBITDAX, of less than 4.0, and an adjusted current ratio, as defined by our credit agreement, of no less than 1.0. Please refer to the caption Non-GAAP Financial Measures below. As of the filing date of this report, we are in compliance with all financial and non-financial covenants under our credit facility.

Our daily weighted-average credit facility debt balance was approximately $313.5 million for the three months ended March 31, 2015. We had no outstanding balance on our credit facility during the three months ended March 31, 2014, as we had a cash balance at year-end 2013 upon closing our Anadarko Basin divestiture. Cash flows provided by our operating activities, proceeds received from divestitures of properties, and the amount of our capital expenditures all impact the amount we have borrowed under our credit facility.

Weighted-Average Interest Rates

Our calculated weighted-average interest rates include paid and accrued interest, fees on the unused portion of the credit facility's aggregate commitment amount, letter of credit fees, and the non-cash amortization of deferred financing costs. Our calculated weighted-average borrowing rates include paid and accrued interest only.

The following table presents our weighted-average interest rates and our weighted-average borrowing rates for the three months ended March 31, 2015, and 2014:

	For the Three Months Ended March 31,			
	2015		2014	
Weighted-average interest rate	6.1	%	6.8	%
Weighted-average borrowing rate	5.6	%	6.1	%

Our weighted-average interest rates and weighted-average borrowing rates in 2015 and 2014 have been impacted by the timing of Senior Notes issuances, the average balance on our revolving credit facility, and the fees paid on the unused portion of our aggregate commitment.

Uses of Cash

We use cash for the acquisition, exploration, and development of oil and gas properties and for the payment of operating and G&A costs, income taxes, dividends, and debt obligations, including interest. Expenditures for the exploration and development of oil and gas properties are the primary use of our capital resources. In the first three months of 2015, we spent $555.0 million for exploration and development capital activities and proved and unproved oil and gas property acquisitions. This amount differs from the cost incurred amount, which is accrual-based and includes asset retirement obligation, geological and geophysical expenses (“G&G”), and exploration overhead amounts. The amount and allocation of future capital expenditures will depend upon a number of factors, including the number and size of acquisition opportunities, our cash flows from operating, investing, and financing activities, and our ability to assimilate acquisitions and execute our drilling program. In addition, the impact of oil, gas, and NGL prices on investment opportunities, the availability of capital, and the timing and results of our operated and non-operated development and exploratory activities may lead to changes in funding requirements for future development. We periodically review our capital expenditure budget to assess changes in current and projected cash flows, acquisition and divestiture activities, debt requirements, and other factors.

We may from time to time repurchase certain amounts of our outstanding debt securities for cash and/or through exchanges for other securities. Such repurchases or exchanges may be made in open market transactions, privately negotiated transactions, or otherwise. Any such repurchases or exchanges will depend on prevailing market conditions, our liquidity requirements, contractual restrictions, compliance with securities laws, and other factors. The amounts involved in any such transaction may be material.

As of the filing date of this report, we could repurchase up to 3,072,184 shares of our common stock under our stock repurchase program, subject to the approval of our Board of Directors. Shares may be repurchased from time to time in the open market, or in privately negotiated transactions, subject to market conditions and other factors, including certain provisions of our credit facility, the indentures governing our Senior Notes, compliance with securities laws, and the terms and provisions of our stock repurchase program. Our Board of Directors reviews this program as part of the allocation of our capital. We currently do not plan to repurchase any outstanding shares during 2015.

The following table presents changes in cash flows between the three months ended March 31, 2015, and 2014. The analysis following the table should be read in conjunction with our condensed consolidated statements of cash flows in Part I, Item 1 of this report.

	For the Three Months Ended March 31,		Amount Change Between Periods	Percent Change Between Periods
	2015	2014		
	(in millions)			
Net cash provided by operating activities	$283.9	$299.7	$(15.8)	(5)%
Net cash used in investing activities	$(534.5)	$(345.5)	$(189.0)	55%
Net cash provided by (used in) financing activities	$250.4	$—	$250.4	N/A

Analysis of Cash Flow Changes Between the Three Months Ended March 31, 2015, and 2014

Operating activities. Cash received from oil, gas, and NGL production revenues, net of transportation costs and production taxes, and including derivative cash settlements, for the three months ended March 31, 2015, was $493.7 million, which is relatively flat compared to $492.0 million for the same period in 2014. Cash paid for LOE increased $16.5 million to $78.5 million for the first three months of 2015, compared to the same period in 2014 due to an increase in production volumes.

Investing activities. Capital expenditures for the first three months of 2015 increased 55 percent compared with the same period in 2014 due to increased spending in our Eagle Ford shale and Bakken/Three Forks programs in early

2015. Acquisitions of proved and unproved properties increased $10.3 million as a result of an acquisition in our Gooseneck area in Divide County, North Dakota in the first quarter of 2015. Net proceeds from the sale of oil and gas properties increased $19.6 million for the three months ended March 31, 2015, compared to the same period in 2014, due to the divestiture of assets held for sale as of December 31, 2014, and the final settlement of our 2013 Anadarko Basin divestiture during the first quarter of 2015.

Financing activities. We had net borrowings under our credit facility of $250.5 million during the three months ended March 31, 2015, and no borrowings or repayments during the same period in 2014.

Interest Rate Risk and Commodity Price Risk

We are exposed to market risk due to the floating interest rate on our revolving credit facility. Our credit agreement allows us to fix the interest rate for all or a portion of the principal balance of our revolving credit facility for a period up to six months. To the extent that the interest rate is fixed, interest rate changes will affect the credit facility's fair market value, but will not impact results of operations or cash flows. Conversely, for the portion of the credit facility that has a floating interest rate, interest rate changes will not affect the fair market value, but will impact future results of operations and cash flows. Changes in interest rates do not impact the amount of interest we pay on our fixed-rate Senior Notes, but can impact their fair market values. As of March 31, 2015, our fixed-rate debt and floating-rate debt outstanding totaled $2.2 billion and $416.5 million, respectively. The carrying amount of our floating rate debt at March 31, 2015, approximates its fair value. Please refer to Note 11 - Fair Value Measurements in Part I, Item 1 of this report for additional discussion on the fair value of our Senior Notes.

The prices we receive for our oil, gas, and NGL production directly impact our revenue, overall profitability, access to capital, and future rate of growth. Oil, gas, and NGL prices are subject to wide fluctuations in response to changes in supply and demand. The markets for oil, gas, and NGLs have been volatile, especially in recent months, and these markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control.

We enter into commodity derivative contracts in order to reduce the impact of fluctuations in commodity prices. Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report for additional information about our oil, gas, and NGL derivative contracts.

There has been no material change to the interest rate risk analysis or oil and gas price sensitivity analysis previously disclosed. Please refer to Interest Rate Risk and Commodity Price Risk in Management's Discussion and Analysis of Financial Condition and Results of Operations in Part II, Item 7 of our 2014 Form 10-K for further discussion.

Off-Balance Sheet Arrangements

As part of our ongoing business, we have not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities ("SPEs"), which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. We evaluate our transactions to determine if any variable interest entities exist. If it is determined that we are the primary beneficiary of a variable interest entity, that entity is consolidated into our consolidated financial statements. We have not been involved in any unconsolidated SPE transactions in 2015.

Critical Accounting Policies and Estimates

Please refer to the corresponding section in Part II, Item 7 and to Note 1 - Summary of Significant Accounting Policies included in Part II, Item 8 of our 2014 Form 10-K for discussion of our accounting policies and estimates.

New Accounting Pronouncements

Please refer to Note 2 - Basis of Presentation, Significant Accounting Policies, and Recently Issued Accounting Standards under Part I, Item 1 of this report for new accounting matters.

Non-GAAP Financial Measures

Adjusted EBITDAX represents income (loss) before interest expense, other non-operating income or expense, income taxes, depreciation, depletion, amortization and accretion expense, exploration expense, property impairments, non-cash stock compensation expense, derivative gains and losses net of settlements, change in the Net Profits Plan liability, and gains and losses on divestitures. Adjusted EBITDAX excludes certain items that we believe affect the comparability of operating results and can exclude items that are generally one-time in nature or whose timing and/or amount cannot be reasonably estimated. Adjusted EBITDAX is a non-GAAP measure that is presented because we believe that it provides useful additional information to investors and analysts, as a performance measure, for analysis of our ability to internally generate funds for exploration, development, acquisitions, and to service debt. We are also subject to a financial covenant under our credit facility based on our debt to adjusted EBITDAX ratio. In addition, adjusted EBITDAX is widely used by professional research analysts and others in the valuation, comparison, and investment recommendations of companies in the oil and gas exploration and production industry, and many investors use the published research of industry research analysts in making investment decisions. Adjusted EBITDAX should not be considered in isolation or as a substitute for net income (loss), income (loss) from operations, net cash provided by operating activities, or profitability or liquidity measures prepared under GAAP. Because adjusted EBITDAX excludes some, but not all items that affect net income (loss) and may vary among companies, the adjusted EBITDAX amounts presented may not be comparable to similar metrics of other companies.

The following table provides reconciliations of our net income (loss) and net cash provided by operating activities to adjusted EBITDAX for the periods presented:

	For the Three Months Ended March 31,	
	2015	2014
	(in thousands)	
Net income (loss) (GAAP)	$(53,058)	$65,607
Interest expense	32,647	24,190
Other non-operating income, net	(571)	(26)
Income tax expense (benefit)	(33,453)	38,863
Depreciation, depletion, amortization, and asset retirement obligation liability accretion	217,401	177,215
Exploration [1]	35,732	19,938
Impairment of proved properties	55,526	—
Abandonment and impairment of unproved properties	11,627	2,801
Stock-based compensation expense	6,024	6,344
Derivative (gain) loss	(154,167)	97,662
Derivative settlement gain (loss) [2]	161,229	(28,940)
Change in Net Profits Plan liability	(4,334)	(1,776)
(Gain) loss on divestiture activity	35,802	(2,958)
Other, net	1,450	—
Adjusted EBITDAX (Non-GAAP)	311,855	398,920
Interest expense	(32,647)	(24,190)
Other non-operating income, net	571	26
Income tax benefit (expense)	33,453	(38,863)
Exploration [1]	(35,732)	(19,938)
Exploratory dry hole expense	16,275	—
Amortization of deferred financing costs	1,957	1,477
Deferred income taxes	(33,727)	38,374
Plugging and abandonment	(2,425)	(1,325)
Other, net	46	(3,103)
Changes in current assets and liabilities	24,296	(51,650)

Net cash provided by operating activities (GAAP)	$283,922	$299,728

(1) Stock-based compensation expense is a component of exploration expense and general and administrative expense on the accompanying statements of operations. Therefore, the exploration line items shown in the reconciliation above will vary from the amount shown on the accompanying statements of operations for the component of stock-based compensation expense recorded to exploration.
(2) Derivative settlement gain (loss) is reported net of the change in accrued settlements between periods in the derivative cash settlements line item on the condensed consolidated statements of cash flows within net cash provided by operating activities.

Cautionary Information about Forward-Looking Statements

This report contains "forward-looking statements" within the meaning of Section 27A of the Securities Act and Section 21E of the Securities Exchange Act of 1934 (the "Exchange Act"). All statements, other than statements of historical facts, included in this report that address activities, events, or developments with respect to our financial condition, results of operations, or economic performance that we expect, believe, or anticipate will or may occur in the future, or that address plans and objectives of management for future operations, are forward-looking statements. The words "anticipate," "assume," "believe," "budget," "estimate," "expect," "forecast," "intend," "plan," "project," "will," and similar ex intended to identify forward-looking statements. Forward-looking statements appear in a number of places in this report, and include statements about such matters as:

- the amount and nature of future capital expenditures and the availability of liquidity and capital resources to fund capital expenditures;
- the drilling of wells and other exploration and development activities and plans, as well as possible future acquisitions;
- the possible divestiture or farm-down of, or joint venture relating to, certain properties;
- proved reserve estimates and the estimates of both future net revenues and the present value of future net revenues associated with those proved reserve estimates;
- future oil, gas, and NGL production estimates;
- our outlook on future oil, gas, and NGL prices, well costs, and service costs;
- cash flows, anticipated liquidity, and the future repayment of debt;
- business strategies and other plans and objectives for future operations, including plans for expansion and growth of operations or to defer capital investment, and our outlook on our future financial condition or results of operations; and
- other similar matters such as those discussed in the Management's Discussion and Analysis of Financial Condition and Results of Operations section of this report.

Our forward-looking statements are based on assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions, expected future developments, and other factors that we believe are appropriate under the circumstances. These statements are subject to a number of known and unknown risks and uncertainties, which may cause our actual results and performance to be materially different from any future results or performance expressed or implied by the forward-looking statements. Some of these risks are described under Risk Factors in Part I, Item 1A of our 2014 Form 10-K, and include such factors as:

- the volatility of oil, gas, and NGL prices, and the effect it may have on our profitability, financial condition, cash flows, access to capital, and ability to grow production volumes and/or proved reserves;
- weakness in economic conditions and uncertainty in financial markets;
- our ability to replace reserves in order to sustain production;
- our ability to raise the substantial amount of capital required to develop and/or replace our reserves;
- our ability to compete against competitors that have greater financial, technical, and human resources;
- our ability to attract and retain key personnel;

- the imprecise estimations of our actual quantities and present value of proved oil, gas, and NGL reserves;
- the uncertainty in evaluating recoverable reserves and estimating expected benefits or liabilities;
- the possibility that exploration and development drilling may not result in commercially producible reserves;
- our limited control over activities on outside operated properties;
- our reliance on the skill and expertise of third-party service providers on our operated properties;
- the possibility that title to properties in which we have an interest may be defective;
- the possibility that our planned drilling in existing or emerging resource plays using some of the latest available horizontal drilling and completion techniques is subject to drilling and completion risks and may not meet our expectations for reserves or production;
- the uncertainties associated with acquisitions, divestitures, joint ventures, farm-downs, farm-outs and similar transactions with respect to certain assets, including whether such transactions will be consummated or completed in the form or timing and for the value that we anticipate;
- the uncertainties associated with enhanced recovery methods;
- our commodity derivative contracts may result in financial losses or may limit the prices we receive for oil, gas, and NGL sales;
- the inability of one or more of our service providers, customers, or contractual counterparties to meet their obligations;
- our ability to deliver necessary quantities of natural gas or crude oil to contractual counterparties;
- price declines or unsuccessful exploration efforts resulting in write-downs of our asset carrying values;
- the impact that lower oil, gas, or NGL prices could have on the amount we are able to borrow under our credit facility;
- the possibility our amount of debt may limit our ability to obtain financing for acquisitions, make us more vulnerable to adverse economic conditions, and make it more difficult for us to make payments on our debt;
- the possibility that covenants in our debt agreements may limit our discretion in the operation of our business, prohibit us from engaging in beneficial transactions, or lead to the accelerated payment of our debt;
- operating and environmental risks and hazards that could result in substantial losses;
- the impact of seasonal weather conditions and lease stipulations on our ability to conduct drilling activities;
- our ability to acquire adequate supplies of water and dispose of or recycle water we use at a reasonable cost in accordance with environmental and other applicable rules;
- complex laws and regulations, including environmental regulations, that result in substantial costs and other risks;
- the availability and capacity of gathering, transportation, processing, and/or refining facilities;
- our ability to sell and/or receive market prices for our oil, gas, and NGLs;
- new technologies may cause our current exploration and drilling methods to become obsolete;
- the possibility of security threats, including terrorist attacks and cybersecurity breaches, against, or otherwise impacting, our facilities and systems;

- the possibility we may face unforeseen difficulties or expenses related to our implementation of a new enterprise resource planning software system; and

- litigation, environmental matters, the potential impact of legislation and government regulations, and the use of management estimates regarding such matters.

We caution you that forward-looking statements are not guarantees of future performance and actual results or performance may be materially different from those expressed or implied in the forward-looking statements. The forward-looking statements in this report speak as of the filing date of this report. Although we may from time to time voluntarily update our prior forward-looking statements, we disclaim any commitment to do so except as required by securities laws.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by this item is provided under Interest Rate Risk and Commodity Price Risk in Item 2 above and is incorporated herein by reference. Please also refer to the information under Interest Rate Risk and Commodity Price Risk in Management's Discussion and Analysis of Financial Condition and Results of Operations in Part II, Item 7 of our 2014 Form 10-K.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures that is designed to reasonably ensure that information required to be disclosed in our SEC reports is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms, and to reasonably ensure that such information is accumulated and communicated to our management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow for timely decisions regarding required disclosure.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) ("Disclosure Controls") will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls will be modified as systems change and conditions warrant.

An evaluation of the effectiveness of the design and operation of our Disclosure Controls was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our Disclosure Controls are effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting

Effective January 1, 2015, we implemented a new enterprise resource planning system (“ERP”) that materially affected our internal control over financial reporting. In connection with this ERP implementation, we updated our internal control over financial reporting, as necessary, to accommodate modifications to our business processes and accounting procedures. We do not believe that this ERP implementation will have an adverse effect on our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

There have been no material changes to the legal proceedings as previously disclosed in our 2014 Form 10-K, under Part I, Item 3. See Note 6 - Commitments and Contingencies, in Part I, Item 1 of this report, for additional discussion.

ITEM 1A. RISK FACTORS

There have been no material changes to the risk factors as previously disclosed in our 2014 Form 10-K.

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

(c) The following table provides information about purchases by the Company or any “affiliated purchaser” (as defined in Rule 10b-18(a)(3) under the Exchange Act) during the fiscal quarter ended March 31, 2015, of shares of the Company’s common stock, which is the sole class of equity securities registered by the Company pursuant to Section 12 of the Exchange Act:

PURCHASES OF EQUITY SECURITIES BY ISSUER
AND AFFILIATED PURCHASERS

	(a)	(b)	(c)	(d)
Period	Total Number of Shares Purchased [1]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Maximum Number of Shares that May Yet Be Purchased Under the Program [2]
01/01/15 - 01/31/15	—	$—	—	3,072,184
02/01/15 - 02/28/15	—	—	—	3,072,184
03/01/15 - 03/31/15	465	52.34	—	3,072,184
Total:	465	$52.34	—	3,072,184

(1) All shares purchased in the first quarter of 2015 were to offset tax withholding obligations that occurred upon the delivery of outstanding shares underlying RSUs delivered under the terms of grants under our Equity Incentive Compensation Plan.

(2) In July 2006, our Board of Directors approved an increase in the number of shares that may be repurchased under the original August 1998 authorization to up to 6,000,000 shares as of the effective date of the resolution. Accordingly, as of the date of this filing, we may repurchase up to 3,072,184 shares of common stock on a prospective basis, subject to the approval of our Board of Directors. The shares may be repurchased from time to time in open market transactions or privately negotiated transactions, subject to market conditions and other factors, including certain provisions of our credit facility, the indentures governing our Senior Notes and compliance with securities laws. Stock repurchases may be funded with existing cash balances, internal cash flow, or borrowings under our credit facility. The stock repurchase program may be suspended or discontinued at any time.

Our payment of cash dividends to our stockholders is subject to covenants under the terms of our credit facility that limit our annual dividend payments to no more than $50.0 million per year. We are also subject to certain covenants under our Senior Notes that restrict certain payments, including dividends; provided, however, that the first $6.5 million of dividends paid each year are not restricted by these covenants. We do not anticipate that these restrictions will limit our payment of dividends at our current rate for the foreseeable future if declared by our Board of Directors.

ITEM 6. EXHIBITS

The following exhibits are filed or furnished with or incorporated by reference into this report:

Exhibit	Description
12.1*	Computation of Ratio of Earnings to Fixed Charges
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes - Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes - Oxley Act of 2002
32.1**	Certification pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document

* Filed with this report.
** Furnished with this report.

SIGNATURES

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

	SM ENERGY COMPANY
May 6, 2015	By: /s/ JAVAN D. OTTOSON Javan D. Ottoson President and Chief Executive Officer (Principal Executive Officer)
May 6, 2015	By: /s/ A. WADE PURSELL A. Wade Pursell Executive Vice President and Chief Financial Officer (Principal Financial Officer)
May 6, 2015	By: /s/ MARK T. SOLOMON Mark T. Solomon Vice President - Controller and Assistant Secretary (Principal Accounting Officer)