SM Energy Co
Form 10-Q
October 28, 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 September 30, 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 October 21, 2015, the registrant had 67,974,771 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)

	September 30, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$197	$120
Accounts receivable	171,067	322,630
Derivative asset	347,299	402,668
Prepaid expenses and other	19,114	19,625
Total current assets	537,677	745,043
Property and equipment (successful efforts method):		
Proved oil and gas properties	7,468,331	7,348,436
Less - accumulated depletion, depreciation, and amortization	(3,240,109)	(3,233,012)
Unproved oil and gas properties	381,869	532,498
Wells in progress	452,436	503,734
Oil and gas properties held for sale, net of accumulated depletion, depreciation and amortization of $74,894 and $22,482, respectively	29,173	17,891
Other property and equipment, net of accumulated depreciation of $43,197 and $37,079, respectively	359,339	334,356
Total property and equipment, net	5,451,039	5,503,903
Noncurrent assets:		
Derivative asset	147,530	189,540
Other noncurrent assets	77,615	78,214
Total other noncurrent assets	225,145	267,754
Total Assets	$6,213,861	$6,516,700
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$361,734	$640,684
Derivative liability	2,900	—
Deferred tax liability	120,563	142,976
Other current liabilities	—	1,000
Total current liabilities	485,197	784,660
Noncurrent liabilities:		
Revolving credit facility	184,000	166,000
Senior Notes (note 5)	2,350,000	2,200,000
Asset retirement obligation	118,153	120,867
Net Profits Plan liability	13,962	27,136
Deferred income taxes	833,352	891,681
Derivative liability	2,019	70
Other noncurrent liabilities	40,341	39,631
Total noncurrent liabilities	3,541,827	3,445,385

Commitments and contingencies (note 6)		
Stockholders' equity:		
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued and outstanding: 67,968,714 and 67,463,060, respectively	680	675
Additional paid-in capital	298,438	283,295
Retained earnings	1,899,803	2,013,997
Accumulated other comprehensive loss	(12,084)	(11,312)
Total stockholders' equity	2,186,837	2,286,655
Total Liabilities and Stockholders' Equity	$6,213,861	$6,516,700

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

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2015	2014	2015	2014
Operating revenues:				
Oil, gas, and NGL production revenue	$366,615	$617,207	$1,201,186	$1,894,977
Net gain (loss) on divestiture activity (note 3)	2,415	(5,432)	38,497	52
Other operating revenues	2,121	7,011	13,548	31,457
Total operating revenues and other income	371,151	618,786	1,253,231	1,926,486
Operating expenses:				
Oil, gas, and NGL production expense	184,568	178,390	554,404	519,697
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	243,879	183,259	680,984	548,255
Exploration	19,679	34,556	82,627	80,161
Impairment of proved properties	55,990	—	124,430	—
Abandonment and impairment of unproved properties	6,600	15,522	24,046	18,487
General and administrative	37,782	41,696	124,026	114,862
Change in Net Profits Plan liability	(4,364)	(6,399)	(13,174)	(15,280)
Derivative (gain) loss	(212,253)	(190,661)	(285,491)	33,470
Other operating expenses	7,166	5,444	34,589	19,505
Total operating expenses	339,047	261,807	1,326,441	1,319,157
Income (loss) from operations	32,104	356,979	(73,210)	607,329
Non-operating income (expense):				
Other, net	27	(672)	623	(2,493)
Interest expense	(33,157)	(22,621)	(96,583)	(70,851)
Loss on extinguishment of debt	—	—	(16,578)	—
Income (loss) before income taxes	(1,026)	333,686	(185,748)	533,985
Income tax (expense) benefit	4,140	(124,748)	78,296	(199,660)
Net income (loss)	$3,114	$208,938	$(107,452)	$334,325
Basic weighted-average common shares outstanding	67,961	67,379	67,638	67,169
Diluted weighted-average common shares outstanding	68,119	68,430	67,638	68,258
Basic net income (loss) per common share	$0.05	$3.10	$(1.59)	$4.98
Diluted net income (loss) per common share	$0.05	$3.05	$(1.59)	$4.90
Dividends per common share	$0.05	$0.05	$0.10	$0.10

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 COMPREHENSIVE INCOME (LOSS) (UNAUDITED)
(in thousands)

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2015	2014	2015	2014
Net income (loss)	$3,114	$208,938	$(107,452)	$334,325
Other comprehensive income (loss), net of tax:				
Pension liability adjustment	(20)	196	(772)	526
Total other comprehensive income (loss), net of tax	(20)	196	(772)	526
Total comprehensive income (loss)	$3,094	$209,134	$(108,224)	$334,851

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 Nine Months Ended September 30, 2015	2014
Cash flows from operating activities:		
Net income (loss)	$(107,452)	$334,325
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Net gain on divestiture activity	(38,497)	(52)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	680,984	548,255
Exploratory dry hole expense	22,860	22,844
Impairment of proved properties	124,430	—
Abandonment and impairment of unproved properties	24,046	18,487
Stock-based compensation expense	20,492	24,568
Change in Net Profits Plan liability	(13,174)	(15,280)
Derivative (gain) loss	(285,491)	33,470
Derivative cash settlements	397,307	(62,894)
Amortization of deferred financing costs	5,803	4,433
Non-cash loss on extinguishment of debt	4,123	—
Deferred income taxes	(80,388)	198,180
Plugging and abandonment	(5,540)	(6,193)
Other, net	3,670	(2,934)
Changes in current assets and liabilities:		
Accounts receivable	105,336	6,476
Prepaid expenses and other	587	234
Accounts payable and accrued expenses	(74,247)	(28,797)
Net cash provided by operating activities	784,849	1,075,122
Cash flows from investing activities:		
Net proceeds from the sale of oil and gas properties	335,103	41,868
Capital expenditures	(1,261,871)	(1,317,862)
Acquisition of proved and unproved oil and gas properties	(7,088)	(459,277)
Other, net	(990)	(714)
Net cash used in investing activities	(934,846)	(1,735,985)
Cash flows from financing activities:		
Proceeds from credit facility	1,604,500	536,500
Repayment of credit facility	(1,586,500)	(146,500)
Net proceeds from Senior Notes	490,951	—
Repayment of Senior Notes	(350,000)	—
Proceeds from sale of common stock	3,157	2,898
Dividends paid	(3,373)	(3,353)
Net share settlement from issuance of stock awards	(8,502)	(10,576)
Other, net	(159)	(85)
Net cash provided by financing activities	150,074	378,884
Net change in cash and cash equivalents	77	(281,979)
Cash and cash equivalents at beginning of period	120	282,248

Cash and cash equivalents at end of period	$197	$269

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 Nine Months Ended September 30,	
	2015	2014
	(in thousands)	
Cash paid for interest, net of capitalized interest	$88,920	$79,119
Net cash paid for income taxes	$492	$1,979

Dividends of approximately $3.4 million were declared by the Company's Board of Directors, but not paid, as of September 30, 2015, and 2014.

As of September 30, 2015, and 2014, $141.5 million and $404.8 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 net cash used in investing activities in the periods during which the payables are settled.

During the second quarter of 2014, the Company exchanged properties in its Rocky Mountain region for other properties also located in its Rocky Mountain region with a fair value of $6.2 million. The amount of cash consideration paid at closing for agreed upon adjustments is reflected in the acquisition of proved and unproved oil and gas properties line item in the condensed consolidated statements of cash flows.

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. These financial statements do not include all information and notes required by GAAP for annual 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 September 30, 2015, through the filing date of this report. Certain prior period amounts have been reclassified to conform to the current presentation on the accompanying condensed consolidated financial statements.

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 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 adoption is permitted. In August 2015, effective upon release, the FASB issued related new authoritative accounting guidance allowing for deferred financing costs associated with line-of-credit arrangements to continue to be presented as assets. The Company is currently evaluating the provisions of this guidance and assessing its impact on the Company's financial statements and disclosures.

In August 2015, the FASB issued new authoritative accounting guidance to defer the effective date of the new revenue recognition standard by one year. The new revenue recognition standard is now effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2017. Early adoption is permitted but only for annual periods, and interim periods within those annual periods, beginning after December 15, 2016. The Company is currently evaluating the provisions of this guidance and assessing its impact on the Company's financial statements and disclosures.

Other than as disclosed above or in the 2014 Form 10-K, there are no other new accounting standards that would have a material effect on the Company's financial statements and disclosures that have been issued but not yet adopted by the Company as of September 30, 2015, and through the filing date of this report.

Note 3 – Acquisitions, Divestitures, and Assets Held for Sale
Divestitures

During the second quarter of 2015, the Company divested its Mid-Continent assets in separate transactions for total cash proceeds received at closing, which reflect aggregate gross purchase price net of closing adjustments (referred to throughout this report as “divestiture proceeds”) of $316.5 million and an estimated total net gain of $108.4 million. These assets were classified as held for sale as of March 31, 2015, and certain of these assets were written down by $30.0 million during the three months ended March 31, 2015, to reflect fair value less estimated costs to sell. This write-down is reflected in the total net estimated gain of $108.4 million discussed above. These divestitures are subject to normal post-closing adjustments expected to occur in the fourth quarter of 2015 or early 2016.

In conjunction with the Company’s efforts to divest its Mid-Continent assets, the Company previously announced the planned closure of its Tulsa, Oklahoma office in 2015, with the relocation of certain personnel to other Company offices. The Company expects to incur a total of approximately $10 million of exit and disposal costs associated with the severance, retention and relocation of employees, and other related matters, excluding the lease expenses discussed in the next paragraph. For the three and nine months ended September 30, 2015, the Company recorded $1.0 million and $9.5 million, respectively, of exit and disposal costs, the majority of which were recorded as general and administrative expense in the accompanying condensed consolidated statements of operations (“accompanying statements of operations”).

Additionally, during the third quarter of 2015, the Company vacated its office space in Tulsa. The Company has subleased a portion of the space and is currently attempting to sublease the remaining space. As of September 30, 2015, the Company is obligated to pay lease costs of approximately $5.8 million, net of expected income from office space currently subleased, which will be expensed over the duration of the lease, which expires in 2022. This obligation will decrease if the Company successfully subleases additional space.

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. Any subsequent decreases to the estimated fair value less the costs to sell impact the measurement of assets held for sale.

As of September 30, 2015, the accompanying condensed consolidated balance sheets (“accompanying balance sheets”) present $29.2 million of assets held for sale, net of accumulated depletion, depreciation, and amortization expense, which primarily consist of certain non-core assets in the Company’s Permian region and certain assets in exploratory areas that the Company no longer intends to explore and develop in light of the low commodity price environment. There is a corresponding asset retirement obligation liability of approximately $3.3 million for assets held for sale recorded in the asset retirement obligation liability financial statement line item in the accompanying balance sheets. For the nine months ended September 30, 2015, write-downs on certain assets held for sale totaled $98.6 million, which included the $30.0 million write-down recorded on certain Mid-Continent assets in the first quarter 2015 as discussed above. There were minimal adjustments on certain assets held for sale for the three months ended September 30, 2015. Write-downs on assets held for sale are recorded in the net gain (loss) on divestiture activity line item in the accompanying statements of operations.

Subsequent to September 30, 2015, the Company entered into a purchase and sale agreement with a buyer for the sale of certain assets held for sale as of September 30, 2015, in its Permian region. The Company expects to close this transaction in the fourth quarter of 2015 for a purchase price of approximately $26.0 million, subject to customary closing adjustments. The closing of this transaction is subject to the satisfaction of customary closing conditions, and there can be no assurance that the transaction will close on the expected closing date or at all.

The Company determined that none of the planned nor executed asset sales qualify for discontinued operations accounting under financial statement presentation authoritative guidance.

Note 4 - Income Taxes

Income tax expense (benefit) for the three and nine months ended September 30, 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 or loss as of each period end presented.

The provision for income taxes consists of the following:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)			
Current portion of income tax expense (benefit):				
Federal	$—	$—	$—	$—
State	(8,308)	479	2,092	1,480
Deferred portion of income tax expense (benefit)	4,168	124,269	(80,388)	198,180
Total income tax expense (benefit)	$(4,140)	$124,748	$(78,296)	$199,660
	403.5 %	37.4 %	42.2 %	37.4 %

On a year-to-date basis, 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 cumulative effects of Texas and North Dakota enacted rate changes are reflected in the year-to-date deferred portion of income tax expense (benefit). During the nine months ended September 30, 2015, the Company determined certain Oklahoma properties sold in the quarter ended June 30, 2015, qualified for the Oklahoma capital gain deduction which resulted in additional state tax benefit.

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. During the quarter ended September 30, 2015, the IRS initiated an audit of the SM-Mitsui Tax Partnership for 2013. The Company has a significant investment in the underlying assets of the tax partnership.

Note 5 - Long-Term Debt

Revolving Credit Facility

The Company's Fifth Amended and Restated Credit Agreement, as amended (the "Credit Agreement"), 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. Effective as of October 7, 2015, the Company's lenders decreased the borrowing base to $2.0 billion as part of the regularly scheduled semi-annual redetermination under the Credit Agreement. This expected reduction from $2.4 billion was primarily a result of the Company's sale of its Mid-Continent assets completed in the second quarter of 2015, plus adjustments consistent with lower commodity prices. There was no change in the current aggregate lender commitments of $1.5 billion. The next redetermination date is scheduled for April 1, 2016. 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 the Credit 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 Agreement as of September 30, 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 Credit Agreement as of October 21, 2015, September 30, 2015, and December 31, 2014:

	As of October 21, 2015	As of September 30, 2015	As of December 31, 2014
	(in thousands)		
Credit facility balance	$177,500	$184,000	$166,000
Letters of credit [1]	$200	$200	$808
Available borrowing capacity	$1,322,300	$1,315,800	$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 notes shown in the table below (the "Senior Notes"):

	As of September 30, 2015	As of December 31, 2014
	(in thousands)	
6.625% Senior Notes due 2019	$—	$350,000
6.50% Senior Notes due 2021	350,000	350,000
6.125% Senior Notes due 2022	600,000	600,000
6.50% Senior Notes due 2023	400,000	400,000
5.0% Senior Notes due 2024	500,000	500,000
5.625% Senior Notes due 2025	500,000	—
Total Senior Notes	$2,350,000	$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 respective 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 this restricted payment covenant. The Company was in compliance with all covenants under its Senior Notes as of September 30, 2015, and through the filing date of this report.

2019 Notes

On May 7, 2015, the Company commenced a cash tender offer for any and all of its outstanding 6.625% Senior Notes due 2019 (the "2019 Notes") at a price of $1,036.88 per $1,000 of principal amount for all 2019 Notes tendered by May 20, 2015 ("Consent Payment Deadline"), and at a price of $1,006.88 per $1,000 of principal amount for all 2019 Notes properly tendered thereafter. On the Consent Payment Deadline, the Company received tenders and consents from the holders of approximately $242.9 million in aggregate principal amount, or approximately 69%, of its outstanding 2019 Notes in connection with the cash tender offer. Following its entry into the supplemental indenture dated as of May 21, 2015, to the indenture dated as of February 7, 2011, between the Company and U.S. Bank National Association, as Trustee, the Company accepted the 2019 Notes tendered as of the Consent Payment Deadline in exchange for payment of total consideration, including accrued interest, of approximately $256.2 million under the Tender Offer and Consent Solicitation. On June 5, 2015, the Company accepted $1.5 million of 2019 Notes tendered after the Consent Payment Deadline in exchange for payment of total consideration, including accrued interest, of approximately $1.6 million.

On June 22, 2015, the Company redeemed the remaining outstanding 2019 Notes at a redemption price of 103.313% of the principal amount for payment of total consideration, including accrued interest, of approximately $111.5 million.

The Company recorded a loss on extinguishment of debt related to the tender offer and redemption of its 2019 Notes of approximately $16.6 million for the quarter ended June 30, 2015. This amount includes approximately $12.5 million associated with the premium paid for the tender offer and redemption of the 2019 Notes and approximately $4.1 million related to the acceleration of unamortized deferred financing costs.

2025 Notes

On May 21, 2015, the Company issued $500.0 million in aggregate principal amount of 5.625% Senior Notes due 2025 (the "2025 Notes") to certain underwriters in a public offering registered under the Securities Act of 1933, as amended (the “Securities Act”). The 2025 Notes were issued at par and mature on June 1, 2025. The Company received net proceeds of approximately $491.0 million after deducting fees of $9.0 million, which are being amortized as deferred financing costs over the life of the 2025 Notes. The net proceeds were used to fund the consideration paid to the tendering holders of the 2019 Notes and to redeem the remaining un-tendered 2019 Notes, as well as repay outstanding borrowings under the Credit Agreement and for general corporate purposes.

Prior to June 1, 2018, the Company may redeem, on one or more occasions, up to 35% of the aggregate principal amount of the 2025 Notes with the net cash proceeds of certain equity offerings at a redemption price of 105.625% of the principal amount thereof, plus accrued and unpaid interest. The Company may also redeem the 2025 Notes, in whole or in part, at any time after June 1, 2018, and prior to June 1, 2020, at a redemption price equal to 100% of the principal amount of the 2025 Notes to be redeemed, plus a specified make-whole premium and accrued and unpaid interest to the applicable redemption date.

On or after June 1, 2020, the Company may also redeem all or, from time to time during the twelve-month period beginning on June 1 of each applicable year, a portion of the 2025 Notes at the redemption prices set forth below expressed as a percentage of the principal amount redeemed, plus accrued and unpaid interest:

2020	102.813	%
2021	101.875	%
2022	100.938	%
2023 and thereafter	100.000	%

2022 Notes

The Company completed its offer to exchange its 6.125% Senior Notes due 2022 for notes registered under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), on July 10, 2015.

Note 6 - Commitments and Contingencies

Commitments

There were no material changes in commitments during the first nine months of 2015, except as further discussed below. Please refer to Note 6 - Commitments and Contingencies in the Company’s 2014 Form 10-K for additional discussion.

In light of the low commodity price environment, the Company curtailed drilling activity during the first nine months of 2015. For the three and nine months ended September 30, 2015, the Company incurred drilling rig termination fees of $2.2 million and $8.1 million, respectively, which are recorded in the other operating expenses line item in the accompanying statements of operations.

During the third quarter of 2015, the Company entered into an amendment to a gas gathering agreement whereby the Company is subject to certain gathering throughput commitments for five years upon the expansion of the existing third party gathering system. The Company may be required to make periodic deficiency payments for any shortfalls in delivering the minimum annual volume commitment. In the event that no product is delivered in accordance with this agreement, the aggregate undiscounted deficiency payments beginning in 2017 and extending through 2022 would be approximately $142.7 million as of September 30, 2015. As of the filing date of this report, the Company does not expect to incur any material shortfalls.

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.

The Company is subject to routine severance, royalty and joint interest audits from regulatory authorities, non-operators and others, as the case may be, and records accruals for estimated exposure when a claim is deemed probable and estimable. Additionally, the Company is subject to various possible contingencies that arise from third party interpretations of the Company's contracts or otherwise affecting the oil and natural gas industry. Such contingencies include differing interpretations as to the prices at which oil and natural gas sales may be made, the prices that royalty owners are paid for production from their leases, allowable costs under joint interest arrangements, and other matters. At September 30, 2015, the Company had $4.6 million accrued for estimated exposure related to claims for payment of royalties on certain Federal and Indian leases. Although the Company believes that it has properly estimated its exposure with respect to the various contracts, laws and regulations, administrative rulings, and interpretations thereof, adjustments could be required as new interpretations and regulations arise.

Note 7 - Compensation Plans

Performance Share Units Under the Equity Incentive Compensation Plan

The Company grants performance share units ("PSUs") to eligible employees as a part of its long-term 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 certain performance criteria 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. Compensation expense for PSUs is recognized within general and administrative and exploration expense over the vesting periods of the respective awards.

Total compensation expense recorded for PSUs for the three months ended September 30, 2015, and 2014, was $2.4 million and $4.8 million, respectively, and $7.4 million and $11.6 million for the nine months ended September 30, 2015, and 2014, respectively. As of September 30, 2015, there was $21.3 million of total unrecognized compensation expense related to unvested PSU awards, which is being amortized through 2018.

A summary of the status and activity of non-vested PSUs for the nine months ended September 30, 2015, is presented in the following table:

	PSUs [(1)]		Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year	433,660		$73.63
Granted	320,753		$45.34
Vested	(75,353	)	$51.59
Forfeited	(47,787	)	$74.42
Non-vested at end of quarter	631,273		$61.83

(1) The number of awards assumes a multiplier of one. The final number of shares of common stock issued may vary depending on the three-year performance multiplier, which ranges from zero to two.

During the first nine months of 2015, the Company granted 320,753 PSUs with a fair value of $14.5 million as part of its regular annual long-term equity compensation program. These PSUs will fully vest on the third anniversary of the date of the grant. Also, during the first nine months of 2015, the Company settled PSUs that were granted in 2012, which earned a 1.0 times multiplier, by issuing 188,279 net shares of the Company's common stock in accordance with the terms of the respective PSU awards. The Company and the majority of grant recipients mutually agreed to net share settle a portion of the awards to cover income and payroll tax withholdings in accordance with the Company's Equity Incentive Compensation Plan and individual award agreements. As a result, 100,683 shares were withheld to satisfy income and payroll tax withholding obligations that arose upon delivery of the shares underlying the PSUs.

Restricted Stock Units Under the Equity Incentive Compensation Plan

The Company grants restricted stock units ("RSUs") as part of its long-term equity compensation program. Each RSU represents a right to receive one share of the Company's common stock upon settlement of the award at the end of the specified vesting period. Compensation expense for RSUs is recognized within general and administrative expense and exploration expense over the vesting periods of the award.

Total compensation expense recorded for RSUs was $4.1 million and $4.8 million for the three months ended September 30, 2015, and 2014, respectively, and $9.9 million and $10.5 million for the nine months ended

September 30, 2015, and 2014, respectively. As of September 30, 2015, there was $22.7 million of total unrecognized compensation expense related to unvested RSU awards, which is being amortized through 2018.

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A summary of the status and activity of non-vested RSUs for the nine months ended September 30, 2015, is presented in the following table:

	RSUs		Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year	515,724		$68.29
Granted	356,246		$43.72
Vested	(267,244	)	$63.43
Forfeited	(41,330	)	$68.63
Non-vested at end of quarter	563,396		$55.04

During the first nine months of 2015, the Company granted 356,246 RSUs with a fair value of $15.6 million as part of its regular annual long-term equity compensation program. These RSUs will vest one-third of the total grant on each of the next three anniversaries of the date of the grant. Also, during the first nine months of 2015, the Company settled 267,244 RSUs that related to awards granted in previous years. The Company and the majority of grant recipients mutually agreed to net share settle a portion of the awards to cover income and payroll tax withholdings in accordance with the Company's Equity Incentive Compensation Plan and individual award agreements. As a result, the Company issued 181,187 net shares of common stock. The remaining 86,057 shares were withheld to satisfy income and payroll tax withholding obligations that arose upon delivery of the shares underlying those RSUs.

Director Shares

During the first nine months of 2015 and 2014, the Company issued 37,950 and 27,677 shares, respectively, of its common stock to its non-employee directors, under the Company's Equity Incentive Compensation Plan. The Company recorded approximately $271,000 and $196,000 of compensation expense related to these awards for the three months ended September 30, 2015 and 2014, respectively. The Company recorded $1.4 million of compensation expense related to these awards for the nine months ended September 30, 2015, and 2014, respectively.

All shares of common stock issued to the Company's non-employee directors are earned over the one-year service period following the date of grant, unless five years of service has been provided to the Company by the director, in which case that director's shares vest upon the earlier of the completion of the one-year service period or the director retiring from the Board of Directors.

Employee Stock Purchase Plan

Under the Company's Employee Stock Purchase Plan ("ESPP"), eligible employees may purchase shares of the Company's common stock through payroll deductions of up to 15 percent of eligible compensation, without accruing in excess of $25,000 in value from purchases for each calendar year. The purchase price of the stock is 85% of the lower of the fair market value of the stock on the first or last day of the purchase period, and shares issued under the ESPP have no restriction period. The ESPP is intended to qualify under Section 423 of the Internal Revenue Code, as amended ("IRC"). The Company had approximately 1.1 million shares available for issuance under the ESPP as of September 30, 2015. There were 96,285 and 35,249 shares issued under the ESPP during the nine months ended September 30, 2015, and 2014, respectively. The fair value of ESPP grants is measured at the date of grant using the Black-Scholes option-pricing model.

Net Profits Plan

Cash payments made or accrued under the Company's Net Profits Plan totaled $410,000 and $2.6 million for the three months ended September 30, 2015, and 2014, respectively, and $3.6 million and $8.1 million for the nine months ended September 30, 2015, and 2014, respectively, the majority of which were recorded as general and administrative expense within the accompanying statements of operations.

Additionally, the Company accrued or made cash payments under the Net Profits Plan of $3.8 million and $8.3 million for the nine months ended September 30, 2015, and 2014, respectively, as a result of the divestitures of properties subject to the Net Profits Plan. These cash payments are accounted for as a reduction in the net gain (loss) on divestiture activity line item in 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”). During the third quarter of 2015, the Company announced to its employees that it intends to freeze the Pension Plans to new participants, effective December 31, 2015. Employees currently participating in the Pension Plans will continue to earn benefits.

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 September 30,		For the Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)			
Service cost	$1,989	$1,584	$5,963	$4,752
Interest cost	624	548	1,872	1,643
Expected return on plan assets that reduces periodic pension costs	(546)	(494)	(1,637)	(1,483)
Amortization of prior service costs	4	4	13	13
Amortization of net actuarial loss	371	172	1,114	516
Net periodic benefit cost	$2,442	$1,814	$7,325	$5,441

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.

Contributions

The Company contributed $6.4 million to the Pension Plans during the nine months ended September 30, 2015.

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 and nine months ended September 30, 2014.

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.

When there is a loss from continuing operations, as was the case for the nine months ended September 30, 2015, all potentially dilutive shares are anti-dilutive and are consequently excluded from the calculation of diluted net loss per common share. For the nine months ended September 30, 2015, weighted-average anti-dilutive securities related to unvested RSUs and contingent PSUs totaled approximately 380,000 shares, respectively.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands, except per share amounts)			
Net income (loss)	$3,114	$208,938	$(107,452)	$334,325
Basic weighted-average common shares outstanding	67,961	67,379	67,638	67,169
Add: dilutive effect of stock options, unvested RSUs, and contingent PSUs	158	1,051	—	1,089
Diluted weighted-average common shares outstanding	68,119	68,430	67,638	68,258
Basic net income (loss) per common share	$0.05	$3.10	$(1.59)	$4.98
Diluted net income (loss) per common share	$0.05	$3.05	$(1.59)	$4.90

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 September 30, 2015, the Company had commodity derivative contracts outstanding through the second quarter of 2020 for a total of 7.6 million Bbls of oil production, 190.4 million MMBtu of gas production, and 13.7 million Bbls of NGL production. Subsequent to September 30, 2015, the Company entered into one derivative contract through the third quarter of 2016 for 886,000 Bbls of NGL production with a contract price of $20.16 per Bbl. This subsequent derivative contract for propane production is based on Oil Price Information Service ("OPIS") Propane Mont Belvieu Non-TET.

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 September 30, 2015:

Oil Contracts

Oil Swaps

Contract Period	NYMEX WTI Volumes	Weighted-Average Contract Price
	(Bbls)	(per Bbl)
Fourth quarter 2015	1,137,000	$90.15
2016	5,570,000	$88.01
All oil swaps	6,707,000	

Oil Collars

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(Bbls)	(per Bbl)	(per Bbl)
Fourth quarter 2015	869,000	$85.00	$92.19
All oil collars	869,000		

Gas Contracts

Gas Swaps

Contract Period	Volumes	Weighted-Average Contract Price
	(MMBtu)	(per MMBtu)
Fourth quarter 2015	12,499,000	$4.01
2016	80,186,000	$3.61
2017	37,527,000	$4.09
2018	30,606,000	$4.27
2019	24,415,000	$4.34
All gas swaps*	185,233,000	

*Gas swaps are comprised of IF El Paso Permian (2%), IF HSC (95%), IF NGPL TXOK (1%), and IF NNG Ventura (2%).

Gas Collars

Contract Period	Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(MMBtu)	(per MMBtu)	(per MMBtu)
Fourth quarter 2015	5,157,000	$3.99	$4.29
All gas collars*	5,157,000		

*Gas collars are comprised of IF El Paso Permian (6%), IF HSC (89%), and IF NNG Ventura (5%).

NGL Contracts

NGL Swaps

	OPIS Purity Ethane Mont Belvieu		OPIS Propane Mont Belvieu Non-TET		OPIS Normal Butane Mont Belvieu Non-TET		OPS Isobutane Mont Belvieu Non-TET	
Contract Period	Volumes	Weighted-Average Contract Price	Volumes	Weighted-Average Contract Price	Volumes	Weighted-Average Contract Price	Volumes	Weighted-Average Contract Price
	(Bbls)	(per Bbl)	(Bbls)	(per Bbl)	(Bbls)	(per Bbl)	(Bbls)	(per Bbl)
Fourth quarter 2015	—	$ —	941,000	$ 19.60	322,000	$ 24.90	276,000	$ 25.30
2016	3,193,000	$ 8.47	2,746,000	$ 19.09	273,000	$ 25.62	233,000	$ 25.87
2017	2,271,000	$ 9.16	—	$ —	—	$ —	—	$ —
2018	1,671,000	$ 10.65	—	$ —	—	$ —	—	$ —
2019	1,200,000	$ 10.92	—	$ —	—	$ —	—	$ —
2020	539,000	$ 11.13	—	$ —	—	$ —	—	$ —
Total NGL swaps	8,874,000		3,687,000		595,000		509,000	

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 $489.9 million as of September 30, 2015, and a net asset of $592.1 million as of December 31, 2014.

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

	As of September 30, 2015			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity contracts	Current assets	$347,299	Current liabilities	$2,900
Commodity contracts	Noncurrent assets	147,530	Noncurrent liabilities	2,019
Derivatives not designated as hedging instruments		$494,829		$4,919

	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 September 30, 2015, and December 31, 2014, all derivative instruments held by the Company were subject to 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 settle 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 September 30, 2015 (in thousands)	Derivative Assets As of December 31, 2014	Derivative Liabilities As of September 30, 2015	Derivative Liabilities As of December 31, 2014
Gross amounts presented in the accompanying balance sheets	$494,829	$592,208	$(4,919)	$(70)
Amounts not offset in the accompanying balance sheets	(4,919)	(70)	4,919	70
Net amounts	$489,910	$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 September 30, 2015 (in thousands)	For the Three Months Ended September 30, 2014	For the Nine Months Ended September 30, 2015	For the Nine Months Ended September 30, 2014
Derivative settlement (gain) loss:				
Oil contracts	$(90,493)	$517	$(270,622)	$27,435
Gas contracts [1]	(19,167)	1,687	(92,279)	28,563
NGL contracts	(4,035)	(1,930)	(24,818)	6,896
Total derivative settlement (gain) loss [2]	$(113,695)	$274	$(387,719)	$62,894
Total derivative (gain) loss:				
Oil contracts	$(131,728)	$(140,912)	$(138,839)	$(15,367)
Gas contracts	(66,538)	(41,352)	(142,807)	46,263
NGL contracts	(13,987)	(8,397)	(3,845)	2,574
Total derivative (gain) loss [3]	$(212,253)	$(190,661)	$(285,491)	$33,470

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(1) Natural gas derivative settlements for the nine months ended September 30, 2015, include a $15.3 million gain recorded in the second quarter of 2015 on the early settlement of futures contracts as a result of divesting of the Company's Mid-Continent assets.

(2) 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.

(3) 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 September 30, 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 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 in the accompanying balance sheets and where they are classified within the fair value hierarchy as of September 30, 2015:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives [1]	$—	$494,829	$—
Proved oil and gas properties [2]	$—	$—	$56,849
Oil and gas properties held for sale [2]	$—	$—	$3,376
Liabilities:			
Derivatives [1]	$—	$4,919	$—
Net Profits Plan [1]	$—	$—	$13,962

(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.

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

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives [1]	$—	$592,208	$—
Proved oil and gas properties [2]	$—	$—	$33,423
Oil and gas properties 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 September 30, 2015, would differ by approximately $1.5 million. A one percent increase or decrease in the discount rate would result in a change of approximately $500,000. 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 Nine Months Ended September 30, 2015	
	(in thousands)	
Beginning balance	$27,136	
Net decrease in liability [1]	(5,749	)
Net settlements [1] [2]	(7,425	)
Transfers in (out) of Level 3	—	
Ending balance	$13,962	

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(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. The amount in the table includes cash payments made or accrued under the Net Profits Plan of $3.8 million for the nine months ended September 30, 2015, as a result of the divestitures of properties subject to 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 September 30, 2015, or December 31, 2014, as they are recorded at historical value.

	As of September 30, 2015	As of December 31, 2014
	(in thousands)	
6.625% Senior Notes due 2019	$—	$350,018
6.50% Senior Notes due 2021	$336,658	$343,000
6.125% Senior Notes due 2022	$552,000	$556,500
6.50% Senior Notes due 2023	$374,000	$379,000
5.0% Senior Notes due 2024	$423,750	$435,000
5.625% Senior Notes due 2025	$430,000	$—

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.

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 September 30, 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 expense of $56.0 million and $124.4 million for the three and nine months ended September 30, 2015, respectively, due to continued declines in commodity strip prices since year-end 2014, the Company's decision to reduce capital invested in the development of certain prospects in its South Texas & Gulf Coast and Permian regions, and a decline in performance of non-core assets. Proved properties measured at fair value within the accompanying balance sheets totaled $56.8 million as of September 30, 2015. As of December 31, 2014, proved oil and gas properties measured at fair value totaled $33.4 million.

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. The Company recorded abandonment and impairment of unproved oil and gas properties expense of $6.6 million and $24.0 million for the three and nine months ended September 30, 2015, respectively, 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 September 30, 2015, and December 31, 2014.

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. 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. For the nine months ended September 30, 2015, write-downs on certain assets held for sale totaled $98.6 million. There were minimal adjustments on certain assets held for sale for the three months ended September 30, 2015. These write-downs are included within the net gain (loss) on divestiture activity line item on the accompanying statements of operations. Please refer to Note 3 – Acquisitions, Divestitures, and Assets Held for Sale.

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

For the nine months ended September 30, 2015, the Company charged $21.1 million of exploratory well costs to exploration expense related to two unsuccessful exploratory wells that were capitalized as of December 31, 2014. None of the costs were capitalized for a period greater than one year as of December 31, 2014, or at the time the wells were determined to be unsuccessful.

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

This management's 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 production of oil, gas, and NGLs in onshore North America. 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 growth opportunities through both exploration and acquisitions, and seek to maximize the value of our assets through industry leading technology application and outstanding operational execution. We focus on achieving high full-cycle economic returns on our investments and maintaining a simple, strong balance sheet through a conservative approach to leverage.

We currently have development positions in the Eagle Ford shale, Bakken/Three Forks and Permian Basin resource plays that are the focus of our capital investment programs. We also have delineation and exploration programs in the Powder River Basin and in east Texas.

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

- Average net daily production for the three months ended September 30, 2015, was 49.1 MBbls of oil, 471.1 MMcf of gas, and 46.8 MBbls of NGLs, for a quarterly equivalent daily production rate of 174.5 MBOE, compared with 142.5 MBOE for the same period in 2014. Please see additional discussion below under Production Results.

- We recorded net income of $3.1 million, or $0.05 per diluted share, for the three months ended September 30, 2015, compared to net income of $208.9 million, or $3.05 per diluted share, for the three months ended September 30, 2014. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 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 September 30, 2015, totaled $286.6 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 $1.0 billion, including the acquisition of approximately $367.6 million of proved and unproved properties in our Gooseneck prospect area and in the Powder River Basin. 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 September 30, 2015, was $259.4 million, compared to $406.2 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 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 second and third quarters of 2015, as well as the third quarter of 2014:

	For the Three Months Ended		
	September 30, 2015	June 30, 2015	September 30, 2014
Crude Oil (per Bbl):			
Average daily NYMEX price	$46.48	$57.85	$97.60
Realized price, before the effect of derivative settlements	$40.03	$51.45	$86.56
Effect of derivative settlements	$20.02	$14.53	$(0.12)
Natural Gas:			
Average daily NYMEX price (per MMBtu)	$2.75	$2.73	$3.94
Realized price, before the effect of derivative settlements (per Mcf)	$2.77	$2.53	$4.49
Effect of derivative settlements (per Mcf) [(1)]	$0.45	$0.88	$(0.05)
Natural Gas Liquids (per Bbl):[(2)]			
Average daily OPIS price	$18.22	$20.79	$39.37
Realized price, before the effect of derivative settlements	$15.18	$16.85	$34.86
Effect of derivative settlements	$0.94	$—	$0.61

(1) Natural gas derivative settlements for the three months ended June 30, 2015, includes a $15.3 million gain on the early settlement of futures contracts as a result of divesting our Mid-Continent assets during the second quarter of 2015, increasing the effect of derivative settlements by $0.35 per Mcf.

(2) 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 affects the price of oil. Oil prices have remained under downward pressure in recent months due to slower forecasted global economic growth combined with excess global supply. In response to lower oil prices at the end of 2014 and the first three quarters of 2015, industry participants have significantly cut capital spending, which we expect will result in lower supply. Gas prices also remain under downward pressure as supply has exceeded demand, resulting in higher levels of gas in storage compared to 2014 and compared to the 5-year average. Excess supply of ethane and propane with higher volumes in storage than historical averages has resulted in a further drop in pricing for those products in recent months. 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 October 21, 2015, and September 30, 2015:

	As of October 21, 2015	As of September 30, 2015
NYMEX WTI oil (per Bbl)	$48.31	$48.15

NYMEX Henry Hub gas (per MMBtu)	$ 2.68	$ 2.75
OPIS NGLs (per Bbl)	$ 18.64	$ 19.45

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 and the caption titled Commodity Price Risk in Overview of Liquidity and Capital Resources below for additional information regarding our oil, gas, and NGL derivatives.

Third Quarter 2015 Highlights and Outlook for the Remainder of 2015

Operational Activities. 2015 has been a year of transition as the broader oil and gas industry adjusts to lower oil prices. We scaled back activity during the first three quarters of 2015 by reducing the number of active drilling rigs and deferring the completion of certain drilled wells. We have realized significant drilling and completion cost reductions during 2015 as our service providers have responded to this commodity price decline. Our goal is to be well positioned in the current commodity price environment as we enter 2016, with a focus on maintaining a strong balance sheet and strong liquidity. Going forward, we intend to incur capital expenditures near adjusted EBITDAX levels in order to minimize increases in total debt, while having the strength and flexibility to adapt should industry conditions change.

We expect our capital program for 2015 to be approximately $1.28 billion. For the nine months ended September 30, 2015, we incurred approximately $1.10 billion for exploration and development activities, net of proved and unproved property acquisitions, estimated asset retirement obligations, and capitalized interest. Please refer to the caption titled Costs Incurred in Oil and Gas Producing Activities below.

Throughout the third quarter of 2015, we operated four drilling rigs in our operated Eagle Ford shale program in south Texas, and we plan to maintain a four rig program for the remainder of the year. Beginning in 2014 and continuing into 2015, our development program shifted to utilizing longer laterals and completions with higher sand loadings. Results from these enhanced completion techniques suggest improved well performance. As of September 30, 2015, in our operated Eagle Ford shale program, we have 64 gross and net wells that have been drilled but not completed. We expect this inventory to increase in the fourth quarter. We continue to test well and completion design and spacing and the prospectivity of the Upper Eagle Ford on our acreage.

In our non-operated Eagle Ford shale program, the operator started the third quarter of 2015 operating five drilling rigs and released three rigs during the quarter. We expect the operator to continue running two rigs for the remainder of the year.

In our Bakken/Three Forks program, we began the third quarter of 2015 operating four drilling rigs. We released two rigs during the third quarter and expect to keep the remaining two rigs operating throughout the rest of the year. We continue to focus most of our activity in Divide County, North Dakota, where we are developing the Three Forks and Bakken intervals. As of September 30, 2015, in our operated Bakken/Three Forks program, we have drilled but not completed 47 gross wells (39 net). We plan on slowing down completion activities during the winter and expect to increase activity again towards the end of the first quarter of 2016. We are monitoring the results of various tests, including completion optimizations and down-spacing of both our operated and non-operated properties in this area.

In our Permian development program, we released our last operated rig during the second quarter of 2015. A large portion of our leasehold position in this region is held by production. In the first quarter of 2016, we expect to return to developing the Wolfcamp and Spraberry intervals on our Sweetie Peck property in Upton County, Texas.

Given the current commodity price environment, we have curtailed activity in our delineation and exploration programs. We have reduced our activity in the Powder River Basin in Wyoming and in east Texas to focus on preserving our more prospective acreage positions. In our Powder River Basin program, we operated one rig during the third quarter and expect to continue operating one rig for the remainder of the year. In east Texas, we are monitoring the performance of exploratory wells previously drilled and completed.

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

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

	South Texas & Gulf Coast	Rocky Mountain	Permian	Total [1]
Oil (MMBbl)	1.8	2.3	0.4	4.5
Gas (Bcf)	39.7	2.3	1.3	43.3
NGLs (MMBbl)	4.2	0.1	—	4.3
Equivalent (MMBOE)	12.6	2.8	0.6	16.1
Avg. daily equivalents (MBOE/d)	137.0	30.6	6.9	174.5
Relative percentage	78 %	18 %	4 %	100 %

(1) Amounts may not calculate due to rounding.

Production increased for the three months ended September 30, 2015, compared to the same period in 2014, driven primarily by the continued development of our Eagle Ford shale and Bakken/Three Forks programs. In our operated Eagle Ford shale and Bakken/Three Forks programs for the three months ended September 30, 2015, we completed nine gross and net wells and 12 gross wells (11 net), respectively. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2015, and 2014 and A three-month and nine-month overview of selected production and financial information, including trends 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 September 30, 2015 (in millions)
Development costs [1]	$253.9
Exploration costs	28.0
Acquisitions	
Proved properties	0.3
Unproved properties [2]	4.4
Total, including asset retirement obligations [3]	$286.6

(1) Includes facility costs of $10.8 million and support facility allocations of $0.8 million for the three months ended September 30, 2015.
(2) Includes $0.9 million of unproved properties acquired as part of proved property acquisitions for the three months ended September 30, 2015. The remaining balance is leasing activity.
(3) Includes amounts relating to estimated asset retirement obligations of $2.9 million and capitalized interest of $5.2 million for the three months ended September 30, 2015.

Costs incurred in oil and gas producing activities, excluding proved and unproved property acquisitions, estimated asset retirement obligations, capitalized interest, and support facility allocations, for the three months ended September 30, 2015, totaled approximately $276.5 million. The majority of costs incurred for oil and gas producing activities during the third quarter of 2015 were in the development of our Eagle Ford shale and Bakken/Three Forks programs. Please refer to Production Results above for discussion on completion activity during the third quarter, in addition to Third Quarter 2015 Highlights and Outlook for the Remainder of 2015 above for discussion on wells that have been drilled during 2015, but not completed as of September 30, 2015. Additionally, please refer to Overview of Liquidity and Capital Resources below for additional discussion on how we expect to fund our capital expenditure program.

Equity Compensation. During the third quarter of 2015, we granted 356,246 RSUs and 320,753 PSUs under our long-term equity incentive program. Additionally, we issued 369,466 shares of our common stock to settle PSU and RSU awards granted in previous years. Please refer to Note 7 - Compensation Plans in Part I, Item 1 of this report for additional discussion.

Subsequent Events. Subsequent to September 30, 2015, our lenders under the Credit Agreement decreased our borrowing base to $2.0 billion as part of the regularly scheduled semi-annual redetermination. Please refer to Note 5 - Long-Term Debt in Part I, Item 1 of this report for additional discussion. Additionally, we entered into a purchase and sale agreement with a buyer for the sale of certain assets held for sale as of September 30, 2015, in our Permian region. Please refer to Note 3 - Acquisitions, Divestitures, and Assets Held for Sale in Part I, Item 1 of this report for additional discussion.

First Nine Months of 2015 Highlights

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

	South Texas & Gulf Coast	Rocky Mountain	Permian	Mid-Continent	Total [1]
Oil (MMBbl)	6.2	7.1	1.5	—	14.8
Gas (Bcf)	113.2	6.6	4.0	9.7	133.5
NGLs (MMBbl)	12.0	0.2	—	—	12.2
Equivalent (MMBOE)	37.0	8.5	2.2	1.7	49.3
Avg. daily equivalents (MBOE/d)	135.5	31.1	7.9	6.1	180.6
Relative percentage	75 %	17 %	4 %	4 %	100 %

(1) Amounts may not calculate due to rounding.

In our operated Eagle Ford shale and Bakken/Three Forks programs for the nine months ended September 30, 2015, we completed 51 gross and net wells and 31 gross wells (27 net), respectively. Please refer to Third Quarter 2015 Highlights and Outlook for the Remainder of 2015 above and Comparison of Financial Results and Trends Between the Nine Months Ended September 30, 2015, and 2014 as well as A three-month and nine-month overview of selected production and financial information, including trends 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 Nine Months Ended September 30, 2015 (in millions)
Development costs [1]	$1,008.1
Exploration costs	108.2
Acquisitions	
Proved properties	9.2
Unproved properties [2]	14.8
Total, including asset retirement obligations [3]	$1,140.3

(1) Includes facility costs of $65.1 million and support facility allocations of $4.9 million for the nine months ended September 30, 2015.
(2) Includes $0.9 million of unproved properties acquired as part of proved property acquisitions for the nine months ended September 30, 2015. The remaining balance is leasing activity.
(3) Includes amounts relating to estimated asset retirement obligations of $11.6 million and capitalized interest of $18.1 million for the nine months ended September 30, 2015.

Costs incurred in oil and gas producing activities, excluding proved and unproved property acquisitions, estimated asset retirement obligations, capitalized interest, and support facility allocation amounts disclosed above for the nine months ended September 30, 2015, totaled approximately $1.10 billion. Please refer to Production Results above for discussion on completion activity for the year to date, in addition to Third Quarter 2015 Highlights and Outlook for the Remainder of 2015 above for discussion on wells that have been drilled during 2015, but not completed as of September 30, 2015. Additionally, please refer to Overview of Liquidity and Capital Resources below for additional discussion on how we expect to fund our capital expenditure program.

Mid-Continent Divestitures. During the second quarter of 2015, we completed the divestiture of our Mid-Continent assets in separate transactions for total divestiture proceeds of $316.5 million, with an estimated net gain of $108.4 million. These divestitures are subject to normal post-closing adjustments. Please refer to Note 3 - Acquisitions, Divestitures, and Assets Held for Sale in Part I, Item 1 of this report for additional information.

2025 Notes. On May 21, 2015, we issued $500.0 million in aggregate principal amount of 2025 Notes. The notes were issued at par and mature on June 1, 2025. We received net proceeds of $491.0 million from this issuance, which we used to fund the consideration paid to the tendering holders of the 2019 Notes and to redeem the remaining un-tendered 2019 Notes, as well as repay outstanding borrowings under our credit facility and for general corporate purposes. Please refer to Note 5 - Long-Term Debt in Part I, Item 1 of this report for additional information.

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			
	September 30, 2015	June 30, 2015	March 31, 2015	December 31, 2014
	(in millions, except for production data)			
Production (MMBOE)	16.1	16.5	16.8	16.2
Oil, gas, and NGL production revenue	$366.6	$441.3	$393.3	$586.6
Oil, gas, and NGL production expense	$184.6	$173.7	$196.2	$196.2
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$243.9	$219.7	$217.4	$219.3
Exploration	$19.7	$25.5	$37.4	$49.7
General and administrative	$37.8	$42.6	$43.6	$52.2
Net income (loss)	$3.1	$(57.5)	$(53.1)	$331.7

Note: Amounts may not calculate due to rounding.

Selected Performance Metrics:

	For the Three Months Ended			
	September 30, 2015	June 30, 2015	March 31, 2015	December 31, 2014
Average net daily production equivalent (MBOE/d)	174.5	181.0	186.4	175.8
Lease operating expense (per BOE)	$3.86	$3.26	$3.96	$4.29
Transportation costs (per BOE)	$6.27	$5.64	$6.08	$5.77
Production taxes as a percent of oil, gas, and NGL production revenue	4.2%	5.2%	4.8%	4.7%
Ad valorem tax expense (per BOE)	$0.40	$0.25	$0.52	$0.37
Depletion, depreciation, amortization, and asset retirement obligation liability accretion (per BOE)	$15.19	$13.34	$12.96	$13.56
General and administrative (per BOE)	$2.35	$2.59	$2.60	$3.23

Note: Amounts may not calculate due to rounding.

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

	For the Three Months Ended September 30, 2015	For the Three Months Ended September 30, 2014	Amount Change Between Periods	Percent Change Between Periods	For the Nine Months Ended September 30, 2015	For the Nine Months Ended September 30, 2014	Amount Change Between Periods	Percent Change Between Periods
Net production volumes [1]								
Oil (MMBbl)	4.5	4.0	0.5	13 %	14.8	11.6	3.3	28 %
Gas (Bcf)	43.3	35.6	7.8	22 %	133.5	109.1	24.4	22 %
NGLs (MMBbl)	4.3	3.2	1.1	35 %	12.2	9.2	3.0	32 %
Equivalent (MMBOE)	16.1	13.1	2.9	22 %	49.3	39.0	10.3	27 %
Average net daily production [1]								
Oil (MBbl per day)	49.1	43.5	5.6	13 %	54.3	42.3	12.0	28 %
Gas (MMcf per day)	471.1	386.5	84.6	22 %	488.9	399.5	89.4	22 %
NGLs (MBbl per day)	46.8	34.6	12.2	35 %	44.8	33.8	11.0	32 %
Equivalent (MBOE per day)	174.5	142.5	31.9	22 %	180.6	142.7	37.9	27 %
Oil, gas, and NGL production revenue (in millions)								
Oil production revenue	$180.9	$346.5	$(165.6)	(48)%	$644.1	$1,029.1	$(385.0)	(37)%
Gas production revenue	120.2	159.6	(39.4)	(25)%	358.9	530.1	(171.2)	(32)%
NGL production revenue	65.5	111.1	(45.6)	(41)%	198.2	335.8	(137.6)	(41)%
Total	$366.6	$617.2	$(250.6)	(41)%	$1,201.2	$1,895.0	$(693.8)	(37)%
Oil, gas, and NGL production expense (in millions)								
Lease operating expense	$62.0	$60.1	$1.9	3 %	$182.3	$166.6	$15.7	9 %
Transportation costs	100.7	81.5	19.2	24 %	295.6	243.7	51.9	21 %
Production taxes	15.4	30.4	(15.0)	(49)%	57.1	89.7	(32.6)	(36)%
Ad valorem tax expense	6.5	6.4	0.1	2 %	19.4	19.7	(0.3)	(2)%
Total	$184.6	$178.4	$6.2	3 %	$554.4	$519.7	$34.7	7 %
Realized price								
Oil (per Bbl)	$40.03	$86.56	$(46.53)	(54)%	$43.43	$89.08	$(45.65)	(51)%
Gas (per Mcf)	$2.77	$4.49	$(1.72)	(38)%	$2.69	$4.86	$(2.17)	(45)%
NGLs (per Bbl)	$15.18	$34.86	$(19.68)	(56)%	$16.20	$36.34	$(20.14)	(55)%
Per BOE	$22.84	$47.06	$(24.22)	(51)%	$24.36	$48.63	$(24.27)	(50)%
Per BOE Data [1]								
Production costs:								
Lease operating expense	$3.86	$4.58	$(0.72)	(16)%	$3.70	$4.27	$(0.57)	(13)%
Transportation costs	$6.27	$6.22	$0.05	1 %	$5.99	$6.25	$(0.26)	(4)%
Production taxes	$0.96	$2.32	$(1.36)	(59)%	$1.16	$2.30	$(1.14)	(50)%
Ad valorem tax expense	$0.40	$0.49	$(0.09)	(18)%	$0.39	$0.51	$(0.12)	(24)%
General and administrative	$2.35	$3.18	$(0.83)	(26)%	$2.52	$2.95	$(0.43)	(15)%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$15.19	$13.97	$1.22	9 %	$13.81	$14.07	$(0.26)	(2)%
Derivative settlement gain (loss) [2]	$7.08	$(0.02)	$7.10	35,500 %	$7.86	$(1.61)	$9.47	588 %

Earnings per share information

Basic net income (loss) per common share	$0.05	$3.10	$(3.05)	(98)%	$(1.59)	$4.98	$(6.57)	(132)%
Diluted net income (loss) per common share	$0.05	$3.05	$(3.00)	(98)%	$(1.59)	$4.90	$(6.49)	(132)%
Basic weighted-average common shares outstanding (in thousands)	67,961	67,379	582	1 %	67,638	67,169	469	1 %
Diluted weighted-average common shares outstanding (in thousands)	68,119	68,430	(311)	— %	67,638	68,258	(620)	(1)%

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(1) Amount and percentage changes may not calculate due to rounding.
(2) Derivative settlements for the three and nine months ended September 30, 2015, and 2014, respectively, are included within the derivative (gain) loss line item in the accompanying statements of operations. Natural gas derivative settlements for the nine months ended

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September 30, 2015, include a $15.3 million gain recorded in the second quarter of 2015 on the early settlement of futures contracts as a result of divesting our Mid-Continent assets. This settlement gain increased our realized natural gas price after the effect of derivative settlements by $0.11 per Mcf for the nine months ended September 30, 2015.

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 and nine months ended September 30, 2015, increased 22 percent and 27 percent, respectively, compared with the same periods in 2014, driven primarily by the continued development of our Eagle Ford shale and Bakken/Three Forks programs. Overall, we expect an increase in production for the full-year 2015 compared to the full-year 2014, even in light of divesting our Mid-Continent assets in the second quarter of 2015. Production declined in the third quarter of 2015 compared to the second quarter of 2015 and we expect this trend to continue in the fourth quarter of 2015. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2015, and 2014 and Comparison of Financial Results and Trends Between the Nine Months Ended September 30, 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 and nine months ended September 30, 2015, decreased 51 percent and 50 percent, respectively, compared to the same periods in 2014 as a result of significantly lower commodity prices.

Lease operating expense (“LOE”) on a per BOE basis for the three and nine months ended September 30, 2015, decreased 16 percent and 13 percent, respectively, compared to the same periods in 2014. Our LOE is comprised of recurring LOE and workover expense. We experience volatility in our LOE as a result of the impact industry activity has on service provider costs and seasonality in workover expense. Industry activity has significantly decreased in light of the weak commodity price environment resulting in service providers lowering costs. We experienced higher LOE on a per BOE basis in the third quarter of 2015 compared to the second quarter of 2015 due to higher workover activity, as well as the fixed cost components of our recurring LOE bearing the decline in quarterly production. We expect this trend to continue for the remainder of 2015. Overall, we expect LOE on a per BOE basis to be lower for the full-year 2015 compared to the full-year 2014.

There was a slight increase in transportation costs on a per BOE basis for the three months ended September 30, 2015, compared to the same period in 2014. There has been a change in our production mix as a result of divesting our Mid-Continent assets near the end of the second quarter of 2015. As these assets had lower transportation costs on a per BOE basis, the divestitures increased our company-wide transportation costs on a per BOE basis for the three months ended September 30, 2015. Transportation costs on a per BOE basis for the nine months ended September 30, 2015, decreased four percent compared to the same period in 2014, as we incurred lower deficiency fees and trucking costs in the first and second quarters of 2015 compared to the same periods in 2014. Overall, we expect minimal change in transportation costs on a per BOE basis for the full-year 2015 compared to full-year 2014 as we expect absolute transportation expense to increase in line with the expected increased production discussed above. The quarterly variances discussed above are expected to offset for the full-year 2015.

Production taxes on a per BOE basis for the three and nine months ended September 30, 2015, decreased 59 percent and 50 percent, respectively, compared to the same periods in 2014. This decrease is driven largely by the decrease in production revenues, as well as a decrease in our company-wide production tax rate as a result of divesting our Mid-Continent properties in the second quarter of 2015. 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 and nine months ended September 30, 2015, decreased 18 percent and 24 percent, respectively, compared to the same periods in 2014. The decrease in ad valorem tax expense on a per BOE basis for the three and nine months ended September 30, 2015, reflects the uncertain nature of estimating this amount in a fluctuating commodity price environment. We expect ad valorem tax expense to fluctuate throughout the year on an absolute and on a per BOE basis as valuations and county tax rates are finalized with an overall decrease on a per BOE basis when comparing full-year 2015 to full-year 2014.

General and administrative ("G&A") expense on a per BOE basis for the three and nine months ended September 30, 2015, decreased 26 percent and 15 percent, respectively, compared to the same periods in 2014. Absolute G&A expense decreased in the third quarter of 2015 due to the closure of the Tulsa office at the beginning of July 2015 with a majority of the exit and disposal costs being incurred in the first half of 2015. Please refer to Note 3 - Acquisitions, Divestitures, and Assets Held for Sale in Part I, Item 1 of this report for additional discussion. For the nine months ended September 30, 2015, G&A expense on a per BOE basis is down compared to the same period in 2014, as production has increased at a faster rate than our G&A expense. We expect this trend to be consistent for the full-year 2015 compared to the full-year 2014. A portion of our G&A 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.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion (“DD&A”) expense on a per BOE basis for the three and nine months ended September 30, 2015, increased nine percent and decreased two percent, respectively, compared to the same periods 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. The continued decrease in commodity prices has resulted in a decrease in proved reserve volumes and consequently an increased DD&A rate in the third quarter of 2015. If commodity prices remain at current levels or decline further, downward revisions of proved reserves due to commodity price impacts may be significant and further increase our DD&A rate. Our DD&A rate for the nine months ended September 30, 2015, has decreased compared to the same period in 2014, 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 the capital cost carry under our Acquisition and Development Agreement with Mitsui E&P Texas LP. This carry was exhausted during the second quarter of 2014 and our DD&A rate has begun to increase as we now pay our full share of costs in our outside-operated Eagle Ford shale program. 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 half of 2015. We expect an increase in our DD&A expense on a per BOE basis for the remainder of 2015.

Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2015, and 2014 and Comparison of Financial Results and Trends Between the Nine Months Ended September 30, 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. For the nine months ended September 30, 2015, we recorded a loss from continuing operations and all potentially dilutive shares were anti-dilutive and excluded from the calculation of diluted net loss per common share.

Comparison of Financial Results and Trends Between the Three Months Ended September 30, 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 September 30, 2015, and 2014:

	Average Net Daily Production Increase (Decrease) (MBOE/d)		Oil, Gas, & NGL Production Revenue Decrease (in millions)		Production Costs Increase (Decrease) (in millions)	
South Texas & Gulf Coast	33.3		$(138.9	)	$23.9	
Rocky Mountain	7.8		(67.1	)	(4.5	)
Permian	(0.4	)	(27.4	)	(4.3	)
Mid-Continent [1]	(8.8	)	(17.2	)	(8.9	)
Total	31.9		$(250.6	)	$6.2	

[1] We divested our Mid-Continent assets in the second quarter of 2015.

Our 22 percent increase in equivalent production volumes is offset by a 51 percent decrease in realized prices on a per BOE basis, resulting in a 41 percent decrease in oil, gas, and NGL production revenue between the two periods. Please refer to A three-month and nine-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 September 30, 2015, and 2014. We expect our realized prices to trend with commodity prices.

Net gain (loss) on divestiture activity. We recorded a net gain on divestiture activity of $2.4 million for the three months ended September 30, 2015, as a result of normal post-closing adjustments on previously closed divestitures, and certain assets held for sale. This compared to a net loss on divestiture activity of $5.4 million for the same period in 2014, which was largely due to the write-down of certain assets held for sale to fair value. Please refer to Note 3 - Acquisitions, Divestitures, and Assets Held for Sale in Part I, Item 1 of this report for additional discussion.

Other operating revenues. The decrease in other operating revenues for the three months ended September 30, 2015, compared to the same period in 2014, is due to decreased marketed gas system revenues resulting from the sale of our Mid-Continent gas assets in the second quarter of 2015.

Oil, gas, and NGL production expense. Total production costs increased three percent for the three months ended September 30, 2015, compared with the same period of 2014, as a result of higher transportation expense due to an increase in net equivalent production volumes. The increase in transportation expense was partially offset by lower service provider costs and decreased production taxes resulting from lower commodity prices. Please refer to A three-month and nine-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 33 percent for the three-month period ended September 30, 2015, compared with the same period in 2014. Increased production and an increasing quarter over quarter DD&A rate is driving DD&A expense higher in 2015. Please refer to A three-month and nine-month overview of selected production and financial information, including trends above for additional discussion of DD&A expense on a per BOE basis.

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

	For the Three Months Ended September 30,	
	2015	2014
	(in millions)	
Geological and geophysical expenses	$0.9	$1.4
Exploratory dry hole	—	16.3
Overhead and other expenses	18.8	16.9
Total	$19.7	$34.6

Exploration expense for the three months ended September 30, 2015, decreased 43 percent compared to the same period in 2014, as a result of exploratory dry hole expense of $16.3 million recorded in the third quarter of 2014 due to a well deemed non-commercial. An exploratory project 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. Given the current commodity price environment, we have reduced exploration activity and expect our exploration expense to decrease as a result.

Impairment of proved properties. We recorded $56.0 million of impairment of proved properties expense for the three months ended September 30, 2015, primarily on legacy assets in our Rocky Mountain region as a result of the continued decline in commodity strip prices. We recorded no impairment of proved properties in the third quarter of 2014. Any amount of future impairments are difficult to predict, but based on updated commodity price assumptions as of October 21, 2015, we do not expect any material impairments in the fourth quarter of 2015 due to commodity price impacts. If commodity prices decline further, downward revisions of proved reserves may be significant and could result in additional impairments in future periods.

Abandonment and impairment of unproved properties. We recorded $6.6 million of abandonment and impairment of unproved properties expense for the three months ended September 30, 2015, as a result of lease expirations and acreage we no longer intended to develop in light of reduced drilling activity and capital expenditure in exploration programs. For the three months ended September 30, 2014, we recorded $15.5 million of expense related to acreage we no longer intended to develop as a result of unsuccessful exploratory activities. We expect our abandonment and impairment of unproved properties expense to fluctuate with the timing of lease expirations, unsuccessful exploration activities, and changing economics associated with volatile commodity prices.

General and administrative. G&A expense decreased nine percent for the three months ended September 30, 2015, compared with the same period of 2014, due to reduced headcount and overhead cost upon closing the Tulsa office in the beginning of the third quarter of 2015. Please refer to A three-month and nine-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 September 30, 2015, and

2014, we recorded a non-cash benefit of $4.4 million and $6.4 million, respectively, as a result of declining commodity prices reducing the corresponding liability. We generally expect changes in our Net Profits Plan liability to correlate with fluctuations in commodity prices.

Derivative (gain) loss. For the three months ended September 30, 2015, and 2014, we recognized a derivative gain of $212.3 million and $190.7 million, respectively, driven by an increase in the fair value of commodity derivative contracts during each period as a result of lower strip pricing. 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 September 30, 2015, and 2014, we recorded other operating expenses of $7.2 million and $5.4 million, respectively. The increase is primarily due to $2.2 million of expense related to the early termination of drilling rig contracts and a $1.0 million materials inventory write-down during the third quarter of 2015. Additionally, marketed gas system expense decreased for the three months ended September 30, 2015, compared to the same period in 2014, as a result of the sale of our Mid-Continent gas assets in the second quarter of 2015.

Income tax (expense) benefit. We recorded income tax benefit of $4.1 million for the three months ended September 30, 2015, compared to expense of $124.7 million for the same period in 2014, resulting in effective tax rates of 403.5 percent and 37.4 percent, respectively. The 2015 benefit tax rate reflects the effect of permanent state items and a nominal pretax book loss for the third quarter of 2015. We expect the full-year 2015 effective tax rate to be relatively consistent with the full-year 2014 effective tax rate. Please refer to Note 4 - Income Taxes in Part I, Item 1 of this report for additional discussion.

Comparison of Financial Results and Trends Between the Nine Months Ended September 30, 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 nine months ended September 30, 2015, and 2014:

	Average Net Daily Production Increase (Decrease) (MBOE/d)	Oil, Gas, & NGL Production Revenue Decrease (in millions)	Production Costs Increase (Decrease) (in millions)
South Texas & Gulf Coast	31.0	$(412.7)	$59.7
Rocky Mountain	9.3	(165.9)	(2.0)
Permian	0.7	(70.6)	(8.7)
Mid-Continent [1]	(3.1)	(44.6)	(14.3)
Total	37.9	$(693.8)	$34.7

[1] We divested our Mid-Continent assets in the second quarter of 2015.

Our 27 percent increase in equivalent production volumes is offset by a 50 percent decrease in realized prices on a per BOE basis, resulting in a 37 percent decrease in oil, gas, and NGL production revenue between the two periods. Please refer to A three-month and nine-month overview of selected production and financial information, including trends above for realized prices received before the effects of derivative settlements for the nine months ended September 30, 2015, and 2014.

Net gain (loss) on divestiture activity. We recorded a net gain on divestiture activity of $38.5 million for the nine months ended September 30, 2015, due to the net gain recorded on the sale of our Mid-Continent assets in the second quarter, partially offset by the write-down to fair value of certain assets held for sale in the first and second quarters of 2015. The gain realized on the sale of properties in our Rocky Mountain region during the second quarter of 2014 was mostly offset by losses recorded on certain assets held for sale in the second and third quarters of 2014. Please refer to Note 3 - Acquisitions, Divestitures, and Assets Held for Sale in Part I, Item 1 of this report for additional discussion.

Other operating revenues. Other operating revenues includes marketed gas system revenues, which decreased for the nine months ended September 30, 2015, compared to the same period in 2014, as a result of the sale of our Mid-Continent assets in the second quarter of 2015. Additionally, other operating revenues for the nine months ended September 30, 2014, included a $10.7 million gain related to our litigation settlement with Endeavour Operating Corporation.

Oil, gas, and NGL production expense. Total production costs increased seven percent for the nine months ended September 30, 2015, compared with the same period of 2014, as a result of a 27 percent increase in net equivalent production volumes, largely offset by lower service provider costs and decreased production taxes resulting from lower commodity prices. Please refer to A three-month and nine-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 24 percent for the nine-month period ended September 30, 2015, compared with the same period in 2014. This increase is mainly due to the increase in production volumes between the two periods. Please refer to A three-month and nine-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 Nine Months Ended September 30,	
	2015	2014
	(in millions)	
Geological and geophysical expenses	$5.6	$7.2
Exploratory dry hole	22.9	22.8
Overhead and other expenses	54.1	50.2
Total	$82.6	$80.2

Exploration expense for the nine months ended September 30, 2015, increased three percent compared to the same period in 2014, primarily due to higher overhead costs, as the exploratory dry holes recorded in both periods were similar in total cost.

Impairment of proved properties. We recorded $124.4 million of impairment of proved properties expense for the nine months ended September 30, 2015, due to our decision, driven by commodity price declines, to reduce capital invested in the development of certain prospects in our South Texas & Gulf Coast and Permian regions during the first quarter of 2015 and a decline in performance on certain non-Eagle Ford assets during the second quarter of 2015. We recorded no impairment of proved properties expense in the nine months ended September 30, 2014. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2015, and 2014 above for additional discussion.

Abandonment and impairment of unproved properties. We recorded $24.0 million of abandonment and impairment of unproved properties expense for the nine months ended September 30, 2015, as a result of lease expirations and acreage we no longer intended to develop in light of reduced drilling activity and capital expenditures in exploration programs. This compares to $18.5 million of expense recorded in the same period of 2014, related to acreage we no longer intended to develop as a result of unsuccessful exploratory activities.

General and administrative. G&A expense increased eight percent for the nine months ended September 30, 2015, compared with the same period of 2014. The increase is primarily driven by approximately $9.5 million of exit and disposal costs recorded during the nine months ended September 30, 2015, related to the closure of our Tulsa office. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2015, and 2014 and A three-month and nine-month overview of selected production and financial information, including trends above for additional discussion.

Change in Net Profits Plan liability. For the nine months ended September 30, 2015, and 2014, we recorded a non-cash benefit of $13.2 million and $15.3 million, respectively. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2015, and 2014 above for additional discussion.

Derivative (gain) loss. We recognized a derivative gain of $285.5 million for the nine months ended September 30, 2015, driven by an increase in the fair value of commodity derivative contracts resulting from the decline in strip pricing during the first and third quarters of 2015, partially offset by a recovery in strip pricing in the second quarter. This compares to a derivative loss of $33.5 million for the same period in 2014, resulting from the loss recognized in the first six months of 2014 being greater than the significant gain recognized in the third quarter as strip prices began to decline during the third quarter of 2014. Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report for additional information.

Other operating expenses. For the nine months ended September 30, 2015, and 2014, we recorded other operating expenses of $34.6 million and $19.5 million, respectively. The increase is primarily due to $8.1 million of expense related to the early termination of drilling rig contracts, $4.6 million of expense related to estimated claims for payment of royalties on certain Federal and Indian leases, as well as a $3.9 million materials inventory write-down during the first nine months of 2015, offset partially by a decrease in marketed gas expense. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2015, and 2014 above for additional discussion.

Loss on extinguishment of debt. For the nine months ended September 30, 2015, we recorded a $16.6 million loss on the early extinguishment of our 2019 Notes during the second quarter, which includes approximately $12.5 million associated with the premium paid for the tender offer and redemption of the notes and approximately $4.1 million for the acceleration of unamortized deferred financing costs. Please refer to Note 5 - Long-Term Debt in Part I, Item 1 of this report for additional information.

Income tax (expense) benefit. We recorded income tax benefit of $78.3 million for the nine-month period ended September 30, 2015, compared to expense of $199.7 million for the same period in 2014, resulting in effective tax rates of 42.2

percent and 37.4 percent, respectively. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2015, and 2014 above 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 or to respond should commodity prices recover.

Sources of Cash

We currently expect our remaining 2015 capital program to be primarily funded by cash flows from operations and proceeds from planned divestitures, with any remaining cash needs to be funded by borrowings under our credit facility. Although we anticipate cash flows from these sources will be sufficient to fund our remaining 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 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. Our borrowing base is subject to regular semi-annual redeterminations and per the Fourth Amendment to the Credit Agreement dated October 7, 2015, the borrowing base decreased from $2.4 billion to $2.0 billion. This expected reduction was primarily a result of the sale of our Mid-Continent assets in the second quarter of 2015, as well as adjustments consistent with lower commodity prices. 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 lender 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 October 21, 2015, September 30, 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 $175.2 million and $272.4 million for the three and nine months ended September 30, 2015, respectively. Our daily weighted-average credit facility debt balance was $41.7 million and $14.1 million for the three and nine months ended September 30, 2014, respectively. 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 and nine months ended September 30, 2015, and 2014:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2015	2014	2015	2014
Weighted-average interest rate	6.0 %	6.6 %	6.0 %	6.7 %
Weighted-average borrowing rate	5.6 %	5.9 %	5.5 %	6.0 %

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. The rates disclosed in the above table for the nine months ended September 30, 2015, do not reflect the approximate $12.5 million premium paid for the tender offer and redemption of the 2019 Notes or the approximate $4.1 million of unamortized deferred financing costs expensed upon extinguishment of these notes during the second quarter of 2015. Please refer to Note 5 - Long-Term Debt in Part I, Item 1 of this report for additional discussion.

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 nine months of 2015, we spent $1.27 billion in capital expenditures and in acquiring proved and unproved oil and gas properties. This amount differs from the costs 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. During the second quarter of 2015, we conducted a tender offer and redeemed our 2019 Notes. Please refer to Note 5 - Long-Term Debt in Part I, Item 1 of this report for additional discussion.

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 periodically 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 nine months ended September 30, 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 Nine Months Ended September 30,		Amount Change Between Periods	Percent Change Between Periods
	2015	2014		
	(in millions)			
Net cash provided by operating activities	$784.8	$1,075.1	$(290.3)	(27)%
Net cash used in investing activities	$(934.8)	$(1,736.0)	$801.2	(46)%
Net cash provided by financing activities	$150.1	$378.9	$(228.8)	(60)%

Analysis of Cash Flow Changes Between the Nine Months Ended September 30, 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, decreased for the nine months ended September 30, 2015, to $1.3 billion compared to $1.5 billion for the same period in 2014. Cash paid for LOE, excluding ad valorem tax expense, increased $33.3 million to $194.4 million for the nine months ended September 30, 2015, compared to the same period in 2014 due to an increase in production volumes partially offset by a reduction in service provider costs. Cash paid for interest, net of capitalized interest, increased $9.8 million for the nine months ended September 30, 2015, compared to the same period in 2014. Additionally, we paid approximately $12.5 million associated with the premium for the tender offer and redemption of the 2019 Notes.

Investing activities. Capital expenditures for the nine months ended September 30, 2015, decreased four percent compared to the same period in 2014. Drilling capital incurred decreased approximately 28 percent for the nine months ended September 30, 2015, compared to 2014, as a result of reduced operated rig count and lower service provider costs. Partially offsetting this decrease in capital activity was our payment, in the first half of 2015, of a significant amount of accrued payables at year-end 2014. We had $7.1 million of acquisition activity during the nine months ended September 30, 2015, compared to $459.3 million of proved and unproved acquisitions in our Gooseneck prospect area and Powder River Basin in the same period in 2014. Net proceeds from the sale of oil and gas properties increased $293.2 million for the nine months ended September 30, 2015, compared to the same period in 2014, due to the divestiture of our Mid-Continent assets during the second quarter of 2015.

Financing activities. For the nine months ended September 30, 2015, we received $491.0 million of net proceeds from the issuance of our 2025 Notes in the second quarter of 2015. These proceeds were primarily used for the tender and redemption of the principal amount of $350.0 million of our 2019 Notes. See the Operating Activities section above for discussion of the associated premium paid. We had net borrowings under our credit facility of $18.0 million and $390.0 million during the nine months ended September 30, 2015, and 2014, respectively.

Interest Rate 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 September 30, 2015, our fixed-rate debt and floating-rate debt outstanding totaled $2.35 billion and $184.0 million, respectively. The carrying amount of our floating rate debt at September 30, 2015, approximates its fair value. Assuming a constant floating-rate debt level of $184.0 million, the before-tax cash flow impact resulting from a 100 basis point change would be $1.8 million over a 12-month period. 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.

Commodity Price Risk

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 and other factors. 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. Based on our production for the nine months ended September 30, 2015, a 10 percent decrease in our average realized oil, gas, and

NGL prices, before the effects of derivative settlements, would have reduced our oil, gas, and NGL production revenues by approximately $64.4 million, $35.9 million, and $19.8 million, respectively.

We enter into commodity derivative contracts in order to reduce the impact of fluctuations in commodity prices. Based on our derivative contracts in place for the nine months ended September 30, 2015, a 10 percent decrease in the contract settlement prices, would have increased our oil, gas, and NGL derivative settlement gain by approximately $36.2 million, $16.2 million, and $5.6 million, respectively. As our current derivative contracts settle in future periods, and if commodity prices remain at current levels or further decline, our adjusted EBITDAX and cash flow from operations will be materially impacted. 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 currently in place and the timing of settlement of those contracts.

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 net 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-based 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 September 30,		For the Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)			
Net income (loss) (GAAP)	$3,114	$208,938	$(107,452)	$334,325
Interest expense	33,157	22,621	96,583	70,851
Other non-operating (income) expense, net	(27)	672	(623)	2,493
Income tax expense (benefit)	(4,140)	124,748	(78,296)	199,660
Depreciation, depletion, amortization, and asset retirement obligation liability accretion	243,879	183,259	680,984	548,255
Exploration [1]	17,798	32,155	77,298	74,696
Impairment of proved properties	55,990	—	124,430	—
Abandonment and impairment of unproved properties	6,600	15,522	24,046	18,487
Stock-based compensation expense	7,277	10,227	20,492	24,568
Derivative (gain) loss	(212,253)	(190,661)	(285,491)	33,470
Derivative settlement gain (loss) [2]	113,695	(274)	387,719	(62,894)
Change in Net Profits Plan liability	(4,364)	(6,399)	(13,174)	(15,280)
Net (gain) loss on divestiture activity	(2,415)	5,432	(38,497)	(52)
Loss on extinguishment of debt	—	—	16,578	—
Other, net	1,045	—	3,901	—
Adjusted EBITDAX (Non-GAAP)	259,356	406,240	908,498	1,228,579
Interest expense	(33,157)	(22,621)	(96,583)	(70,851)
Other non-operating income (expense), net	27	(672)	623	(2,493)
Income tax (expense) benefit	4,140	(124,748)	78,296	(199,660)
Exploration [1]	(17,798)	(32,155)	(77,298)	(74,696)
Exploratory dry hole expense	(36)	16,385	22,860	22,844
Amortization of deferred financing costs	1,911	1,479	5,803	4,433
Deferred income taxes	4,168	124,269	(80,388)	198,180
Plugging and abandonment	(2,154)	(2,974)	(5,540)	(6,193)

Loss on extinguishment of debt	—	—	(12,455)	—
Other, net	3,059	1,893	(231)	(2,934)
Changes in current assets and liabilities	15,825	(7,127)	41,264	(22,087)
Net cash provided by operating activities (GAAP)	$235,341	$359,969	$784,849	$1,075,122

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(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 expense.
(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. Natural gas derivative settlements for the nine months ended September 30, 2015, include a $15.3 million gain on the early settlement of futures contracts as a result of divesting our Mid-Continent assets during the second quarter of 2015.

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 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 expressions are intended to identify forward-lo 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;

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- 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 ("ERP"); 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 were effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting

Effective January 1, 2015, we implemented a new ERP that materially impacted 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. The ERP implementation has not had an adverse impact on our internal control over financial reporting, nor do we expect it to have an adverse impact in future periods.

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 quarter ended September 30, 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

Period	(a) Total Number of Shares Purchased [1]	(b) Weighted Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Program	(d) Maximum Number of Shares that May Yet Be Purchased Under the Program [2]
07/01/15 - 07/31/15	173,592	$46.12	—	3,072,184
08/01/15 - 08/31/15	12,042	37.07	—	3,072,184
09/01/15 - 09/30/15	543	35.47	—	3,072,184
Total:	186,177	$45.50	—	3,072,184

(1) All shares purchased in the third quarter of 2015 offset tax withholding obligations that occurred upon the delivery of outstanding shares underlying RSUs and PSUs 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 the indentures governing 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 any dividends are 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
3.1	Restated Certificate of Incorporation of SM Energy Company, as amended through June 1, 2010 (filed as Exhibit 3.1 to the registrant’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, and incorporated herein by reference)
3.2	Amended and Restated Bylaws of SM Energy Company effective as of December 16, 2014 (filed as Exhibit 3.1 to the registrant’s Current Report on Form 8-K filed on December 19, 2014, and incorporated herein by reference)
4.1	Indenture related to senior debt securities of SM Energy Company by and between SM Energy Company and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the registrant’s Registration Statement on Form S-3 filed on May 7, 2015 (Registration No. 333-203936) and incorporated herein by reference)
4.2	2025 Notes Supplemental Indenture (filed as Exhibit 4.2 to the registrant’s Current Report on Form 8-K filed on May 21, 2015, and incorporated herein by reference)
4.3	2019 Notes Supplemental Indenture (filed as Exhibit 4.3 to the registrant’s Current Report on Form 8-K filed on May 21, 2015 and incorporated herein by reference)
10.1***	Amendment to Amended and Restated Gas Gathering Agreement, effective as of September 1, 2015, by and between SM Energy Company and Regency Field Services LLC (filed as Exhibit 10.1 to the registrant’s Current Report on Form 8-K filed on September 15, 2015, and incorporated herein by reference)
10.2	Fourth Amendment to Fifth Amended and Restated Credit Agreement, dated October 7, 2015, among SM Energy Company, Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders party thereto (filed as Exhibit 10.1 to the registrant’s Current Report on Form 8-K filed on October 8, 2015, and incorporated herein by reference)
10.3	Change of Control Executive Severance Agreement (filed as Exhibit 10.1 to the registrant’s Current Report on Form 8-K filed on October 20, 2015, and incorporated herein by reference)
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

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* Filed with this report.

**	Furnished with this report.
***	Certain portions of this exhibit have been redacted and are the subject of a confidential treatment request pursuant to Rule 24b-2 under the Securities Exchange Act of 1934.

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	
October 28, 2015	By:	/s/ JAVAN D. OTTOSON Javan D. Ottoson President and Chief Executive Officer (Principal Executive Officer)
October 28, 2015	By:	/s/ A. WADE PURSELL A. Wade Pursell Executive Vice President and Chief Financial Officer (Principal Financial Officer)
October 28, 2015	By:	/s/ MARK T. SOLOMON Mark T. Solomon Vice President - Controller and Assistant Secretary (Principal Accounting Officer)

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