SM Energy Co
Form 10-Q
November 02, 2016

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, 2016
Commission File Number 001-31539
SM ENERGY COMPANY
(Exact name of registrant as specified in its charter)

Delaware	41-0518430
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1775 Sherman Street, Suite 1200, Denver, Colorado	80203
(Address of principal executive offices)	(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 26, 2016, the registrant had 86,869,269 shares of common stock, $0.01 par value, outstanding.

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SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)
(in thousands, except share amounts)

	September 30, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 980,666	$ 18
Accounts receivable	140,799	134,124
Derivative asset	109,818	367,710
Prepaid expenses and other	15,326	17,137
Total current assets	1,246,609	518,989
Property and equipment (successful efforts method):		
Proved oil and gas properties	5,406,656	7,606,405
Less - accumulated depletion, depreciation, and amortization	(2,668,060)	(3,481,836)
Unproved oil and gas properties	177,787	284,538
Wells in progress	201,241	387,432
Oil and gas properties held for sale, net	1,109,517	641
Other property and equipment, net of accumulated depreciation of $41,958 and $32,956, respectively	137,553	153,100
Total property and equipment, net	4,364,694	4,950,280
Noncurrent assets:		
Derivative asset	107,029	120,701
Restricted cash	49,000	—
Other noncurrent assets	18,101	31,673
Total other noncurrent assets	174,130	152,374
Total Assets	$ 5,785,433	$ 5,621,643
LIABILITIES AND STOCKHOLDERS’ EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 277,571	$ 302,517
Derivative liability	51,059	8
Total current liabilities	328,630	302,525
Noncurrent liabilities:		
Revolving credit facility	—	202,000
Senior Notes, net of unamortized deferred financing costs (note 5)	2,765,398	2,315,970
Senior Convertible Notes, net of unamortized discount and deferred financing costs (note 5)	128,925	—
Asset retirement obligation	66,158	137,284
Asset retirement obligation associated with oil and gas properties held for sale	46,290	241
Net Profits Plan liability	1,162	7,611
Deferred income taxes	453,712	758,279
Derivative liability	104,705	—
Other noncurrent liabilities	42,538	45,332
Total noncurrent liabilities	3,608,888	3,466,717

Commitments and contingencies (note 6)		
Stockholders’ equity:		
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued and outstanding: 86,868,482 and 68,075,700, respectively	869	681
Additional paid-in capital	866,239	305,607
Retained earnings	994,969	1,559,515
Accumulated other comprehensive loss	(14,162)	(13,402)
Total stockholders’ equity	1,847,915	1,852,401
Total Liabilities and Stockholders’ Equity	$ 5,785,433	$ 5,621,643

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,	
	2016	2015	2016	2015
Operating revenues:				
Oil, gas, and NGL production revenue	$329,165	$366,615	$832,130	$1,201,186
Net gain on divestiture activity (note 3)	22,388	2,415	3,413	38,497
Other operating revenues	1,107	2,121	2,007	13,548
Total operating revenues and other income	352,660	371,151	837,550	1,253,231
Operating expenses:				
Oil, gas, and NGL production expense	152,524	184,568	445,658	554,404
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	193,966	243,879	619,193	680,984
Exploration	13,482	19,679	41,942	82,627
Impairment of proved properties	8,049	55,990	277,834	124,430
Abandonment and impairment of unproved properties	3,568	6,600	5,917	24,046
General and administrative	32,679	37,782	93,117	124,026
Change in Net Profits Plan liability	(8,314)	(4,364)	(6,449)	(13,174)
Derivative (gain) loss	(28,037)	(212,253)	121,086	(285,491)
Other operating expenses	2,397	7,166	14,180	34,589
Total operating expenses	370,314	339,047	1,612,478	1,326,441
Income (loss) from operations	(17,654)	32,104	(774,928)	(73,210)
Non-operating income (expense):				
Interest expense	(47,206)	(33,157)	(112,329)	(96,583)
Gain (loss) on extinguishment of debt	—	—	15,722	(16,578)
Other, net	221	27	232	623
Loss before income taxes	(64,639)	(1,026)	(871,303)	(185,748)
Income tax benefit	23,732	4,140	314,505	78,296
Net income (loss)	$(40,907)	$3,114	$(556,798)	$(107,452)
Basic weighted-average common shares outstanding	78,468	67,961	71,574	67,638
Diluted weighted-average common shares outstanding	78,468	68,119	71,574	67,638
Basic net income (loss) per common share	$(0.52)	$0.05	$(7.78)	$(1.59)
Diluted net income (loss) per common share	$(0.52)	$0.05	$(7.78)	$(1.59)
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,	
	2016	2015	2016	2015
Net income (loss)	$(40,907)	$3,114	$(556,798)	$(107,452)
Other comprehensive loss, net of tax:				
Pension liability adjustment	(255)	(20)	(760)	(772)
Total other comprehensive loss, net of tax	(255)	(20)	(760)	(772)
Total comprehensive income (loss)	$(41,162)	$3,094	$(557,558)	$(108,224)

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY (UNAUDITED)
(in thousands, except share amounts)

	Common Stock		Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholders' Equity
	Shares	Amount				
Balances, December 31, 2015	68,075,700	$ 681	$ 305,607	$ 1,559,515	$ (13,402)	$ 1,852,401
Net loss	—	—	—	(556,798)	—	(556,798)
Other comprehensive loss	—	—	—	—	(760)	(760)
Cash dividends, $ 0.10 per share	—	—	—	(7,748)	—	(7,748)
Issuance of common stock under Employee Stock Purchase Plan	140,853	1	2,353	—	—	2,354
Issuance of common stock upon vesting of RSUs and settlement of PSUs, net of shares used for tax withholdings	198,456	2	(2,343)	—	—	(2,341)
Stock-based compensation expense	53,473	1	20,484	—	—	20,485
Issuance of common stock from stock offering	18,400,000	184	530,728	—	—	530,912
Equity component of 1.50% Senior Convertible Notes due 2021 issuance, net of issuance costs	—	—	38,860	—	—	38,860
Purchase of capped call transactions	—	—	(24,183)	—	—	(24,183)
Deferred tax liability related to integrated Senior Convertible Notes, net	—	—	(5,267)	—	—	(5,267)
Balances, September 30, 2016	86,868,482	$ 869	$ 866,239	$ 994,969	$ (14,162)	$ 1,847,915

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 CASH FLOWS (UNAUDITED)
(in thousands)

	For the Nine Months Ended September 30,	
	2016	2015
Cash flows from operating activities:		
Net loss	$(556,798)	$(107,452)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Net gain on divestiture activity	(3,413)	(38,497)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	619,193	680,984
Exploratory dry hole expense	(16)	22,860
Impairment of proved properties	277,834	124,430
Abandonment and impairment of unproved properties	5,917	24,046
Stock-based compensation expense	20,485	20,492
Change in Net Profits Plan liability	(6,449)	(13,174)
Derivative (gain) loss	121,086	(285,491)
Derivative settlement gain	306,234	387,719
Amortization of discount and deferred financing costs	5,687	5,803
Non-cash (gain) loss on extinguishment of debt, net	(15,722)	4,123
Deferred income taxes	(314,770)	(80,388)
Plugging and abandonment	(5,222)	(5,540)
Other, net	(2,392)	3,670
Changes in current assets and liabilities:		
Accounts receivable	1,221	105,336
Prepaid expenses and other	7,652	587
Accounts payable and accrued expenses	(65,166)	(74,247)
Accrued derivative settlements	19,651	9,588
Net cash provided by operating activities	415,012	784,849
Cash flows from investing activities:		
Net proceeds from the sale of oil and gas properties	201,829	335,103
Capital expenditures	(492,794)	(1,261,871)
Acquisition of proved and unproved oil and gas properties	(21,853)	(7,088)
Acquisition deposit held in escrow	(49,000)	—
Other, net	—	(990)
Net cash used in investing activities	(361,818)	(934,846)
Cash flows from financing activities:		
Proceeds from credit facility	743,000	1,604,500
Repayment of credit facility	(945,000)	(1,586,500)
Debt issuance costs related to credit facility	(3,132)	—
Net proceeds from Senior Notes	492,397	490,951
Cash paid to repurchase Senior Notes	(29,904)	(350,000)
Net proceeds from Senior Convertible Notes	166,681	—
Cash paid for capped call transactions	(24,109)	—
Net proceeds from sale of common stock	533,266	3,157
Dividends paid	(3,404)	(3,373)
Net share settlement from issuance of stock awards	(2,341)	(8,502)

Other, net	—	(159)
Net cash provided by financing activities	927,454	150,074
Net change in cash and cash equivalents	980,648	77
Cash and cash equivalents at beginning of period	18	120
Cash and cash equivalents at end of period	$980,666	$197

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 activities:

	For the Nine Months Ended September 30,	
	2016	2015
	(in thousands)	
Supplemental Cash Flow Information:		
Cash paid for interest, net of capitalized interest [1]	$88,109	$88,920
Net cash (refunded) paid for income taxes	$(4,481)	$492
Supplemental Non-Cash Investing Activities:		
Changes in capital expenditure accruals and other	$(1,287)	$(183,945)

(1) Cash paid for interest, net of capitalized interest for the nine months ended September 30, 2016, does not include the $10.0 million paid to terminate a second lien facility that was no longer necessary to fund acquisition activity.

As of September 30, 2016, $23.6 million of accrued commissions and payments to Net Profits Plan participants related to divestitures were included in accounts payable and accrued expenses in the Company's condensed consolidated balance sheets. As of September 30, 2015, there were no accrued commissions or payments to Net Profits Plan participants related to divestitures.

Additionally, dividends of approximately $4.3 million and $3.4 million were declared by the Company's Board of Directors, but not paid, as of September 30, 2016, and 2015, respectively.

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, together with its consolidated subsidiaries ("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 include the accounts of SM Energy and its wholly-owned subsidiaries and have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP") for interim financial information and the instructions to Quarterly Report on 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, 2015 (the "2015 Form 10-K"). In the opinion of management, all adjustments, consisting of normal recurring adjustments 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 the Company's unaudited condensed consolidated financial statements, the Company evaluated events subsequent to the balance sheet date of September 30, 2016, and through the filing date of this report.

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 2015 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 2015 Form 10-K.

Recently Issued Accounting Standards

Effective January 1, 2016, the Company adopted, on a retrospective basis, Financial Accounting Standards Board ("FASB") Accounting Standards Update ("ASU") No. 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis. This ASU clarifies the consolidation reporting guidance in GAAP. There was no impact to the Company's financial statements or disclosures from the adoption of this standard.

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842), which changes the accounting for leases. This guidance is to be applied using a modified retrospective method and is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2018. Early adoption is permitted. The Company is currently evaluating the provisions of this guidance and assessing its potential impact on the Company's financial statements and disclosures.

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606) ("ASU 2014-09") for the recognition of revenue from contracts with customers. Subsequent to the issuance of this ASU, the

FASB has issued additional related ASUs as follows:

- In August 2015, the FASB issued ASU No. 2015-14, Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date. This ASU deferred the effective date of ASU 2014-09 by one year.
- In March 2016, the FASB issued ASU No. 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net). This ASU amends the principal versus agent guidance in ASU No. 2014-09.
- In April 2016, the FASB issued ASU No. 2016-10, Revenue from Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing. This ASU amends the identification of performance obligations and accounting for licenses in ASU 2014-09.

In May 2016, the FASB issued ASU No. 2016-12, Revenue from Contracts with Customers (Topic 606):
• Narrow-Scope Improvements and Practical Expedients. This ASU amends certain issues in ASU 2014-09 on transition, collectibility, noncash consideration, and the presentation of sales taxes and other similar taxes.

ASU 2014-09 and each update have the same effective date and transition requirements. That is, the guidance under these standards is to be applied using a full retrospective method or a modified retrospective method, as outlined in ASU 2014-09, and is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2017. Early adoption is permitted only for annual periods, and interim periods within those annual periods, beginning after December 15, 2016. The Company is currently evaluating the level of effort necessary to implement the standards, evaluating the provisions of each of these standards, and assessing their potential impact on the Company's financial statements and disclosures, as well as determining whether to use the full retrospective method or the modified retrospective method.

In March 2016, the FASB issued ASU No. 2016-09, Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting. This ASU makes targeted amendments to the accounting for employee share-based payments. This guidance is to be applied using various transition methods, such as full retrospective, modified retrospective, and prospective, based on the criteria for the specific amendments as outlined in the guidance. The guidance is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2016. Early adoption is permitted, as long as all of the amendments are adopted in the same period. The Company is currently evaluating the provisions of this guidance and assessing its potential impact on the Company's financial statements and disclosures.

In August 2016, the FASB issued ASU No. 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments. This ASU is intended to reduce diversity in practice in how certain transactions are classified in the statement of cash flows. This guidance is to be applied using a retrospective method. The guidance is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2017. Early adoption is permitted, as long as all of the amendments are adopted in the same period. The Company is currently evaluating the provisions of this guidance and assessing its potential impact on the Company's financial statements and disclosures.

Other than as disclosed above or in the 2015 Form 10-K, there are no other accounting standards applicable to the Company that would have a material effect on the Company's financial statements and related disclosures that have been issued but not yet adopted by the Company as of September 30, 2016, and through the filing date of this report.

Note 3 – Assets Held for Sale, Divestitures and Acquisitions
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 changes to the fair value less estimated costs to sell impact the measurement of assets held for sale with any gain or loss reflected in the net gain on divestiture activity line item in the accompanying condensed consolidated statements of operations ("accompanying statements of operations").

As of September 30, 2016, the accompanying condensed consolidated balance sheets ("accompanying balance sheets") present $1.1 billion of assets held for sale, net of accumulated depletion, depreciation, and amortization expense, which primarily consists of the Company's outside-operated Eagle Ford shale assets and all of the Company's North Rocky Mountain assets outside of its Divide County program (referred to as "Raven/Bear Den" throughout this report). A corresponding aggregate asset retirement obligation liability of $46.3 million is separately presented. The Company expects to close these transactions by year-end or within the first quarter of 2017. There were no material assets held for sale as of December 31, 2015.

The following table presents income (loss) before income taxes for the three and nine months ended September 30, 2016, and 2015, of the Company's assets held for sale as of September 30, 2016; specifically, its outside-operated Eagle Ford shale assets and Raven/Bear Den assets, each of which are considered a significant asset disposal group.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in thousands)			
Income (loss) before income taxes [1]	$20,309	$(15,132)	$(289,563)	$55,445

[1] Income (loss) before income taxes reflects oil, gas, and NGL production revenue less oil, gas, and NGL production expense, depletion, depreciation, amortization, and asset retirement obligation liability accretion, and related general and administrative expense and exploration overhead. Additionally, loss before income taxes for the nine months ended September 30, 2016, includes $269.6 million of proved property impairments, and income (loss) before income taxes for the three and nine months ended September 30, 2015, includes $17.8 million of proved property impairments.

Subsequent to September 30, 2016, the Company entered into a definitive agreement for the sale of its Raven/Bear Den assets for a gross purchase price of $785.0 million, subject to customary purchase price adjustments. This transaction is expected to close in early December 2016, with the net proceeds expected to be used to partially fund the QStar Acquisition (defined and discussed below). The closing of this divestiture is subject to the satisfaction of customary closing conditions, and there can be no assurance that this transaction will close on the expected closing date or at all.

Divestitures

During the third quarter of 2016, the Company divested certain of its Permian and Rocky Mountain assets in separate packages that were previously classified as held for sale. The Permian assets consisted of non-core properties in New Mexico and were divested for total cash received at closing, net of paid or accrued commissions and payments to Net Profits Plan participants (referred throughout this report as "net divestiture proceeds") of $54.6 million. The Company recorded a net loss of $10.1 million related to these divested assets for the nine months ended September 30, 2016. The Rocky Mountain assets, which consisted of certain non-core properties in the Williston and Powder River Basins, were divested in two separate packages for total net divestiture proceeds of $110.6 million. The Company recorded a net gain of $16.4 million related to these divested assets for the nine months ended September 30, 2016. Certain of these sold assets were written down in the first quarter of 2016 and subsequently written up in the second quarter of 2016 based on changes in the estimated fair value less selling costs. Each of these divestitures is subject to normal post-closing adjustments, and the respective post-closings are expected to occur in the fourth quarter of 2016 or early 2017.

During the second quarter of 2015, the Company divested its Mid-Continent assets in separate packages for net divestiture proceeds received at closing of $310.2 million and recorded a net gain of $108.4 million for the nine months ended September 30, 2015. Final settlement of these divestitures occurred in the fourth quarter of 2015 and first quarter of 2016. In conjunction with these divestitures, the Company closed its Tulsa, Oklahoma office in 2015. Please refer to Note 12 - Exit and Disposal Costs for additional discussion.

The Company determined that neither these planned nor executed asset sales qualified for discontinued operations accounting under financial statement presentation authoritative guidance.

Acquisitions

During the third quarter of 2016, the Company entered into a definitive purchase agreement with Rock Oil Holdings, LLC to acquire all membership interests of JPM EOC Opal, LLC, which owned proved and unproved properties in the Midland Basin, for an aggregate purchase price of $980.0 million, subject to customary purchase price adjustments (referred to throughout this report as the “Rock Oil Acquisition”). Upon executing the purchase agreement, the Company tendered a $49.0 million deposit that was held in escrow as of September 30, 2016, and reflected as restricted cash in the accompanying balance sheets.

The Rock Oil Acquisition closed on October 4, 2016, for an adjusted purchase price of $991.0 million and was funded by the Company’s recent asset divestitures, and the Company’s equity, Senior Convertible Notes, and 2026 Notes offerings during the third quarter of 2016, as defined and discussed in Note 5 - Long-Term Debt and Note 13 - Equity. This acquisition is subject to normal post-closing adjustments that are expected to occur in the fourth quarter of 2016 or early 2017. Final purchase accounting for the Rock Oil Acquisition transaction was not complete at the time this report was filed, and as such, certain disclosures required by ASC Topic

805, Business Combinations, have not been made herein. The Company will include this information in its 2016 Annual Report on Form 10-K.

Subsequent to September 30, 2016, the Company entered into a definitive purchase agreement with QStar LLC ("QStar") to acquire proved and unproved properties in the Midland Basin. Additionally, the Company entered into a Ratification and Joinder Agreement ("Joinder Agreement") with RRP-QStar, LLC ("RRP"), whereby the Company agreed to acquire RRP's interests in the same Midland Basin assets on the same terms and conditions set forth in the agreement with QStar LLC, except as such terms are modified under the Joinder Agreement. Under these agreements, the Company agreed to purchase QStar's and RRP's interest in the Midland Basin assets for $1.1 billion in cash consideration, and approximately 13.4 million shares of the Company's common stock, par value $0.01 per share, as discussed further in Note 13 - Equity. The Company intends to fund the cash portion of the transactions with proceeds from planned asset divestitures and borrowings under the credit facility. Together these transactions are referred to as the "QStar Acquisition" throughout this report and are expected to close mid-December 2016. The closing of the QStar and RRP transactions are subject to the satisfaction of customary closing conditions, and there can be no assurance that either of these transactions will close on the expected closing dates or at all.

Note 4 - Income Taxes

The income tax benefit recorded for each of the three and nine months ended September 30, 2016, and 2015, differs from the amount that would be provided by applying the statutory United States federal income tax rate to income or loss before income taxes primarily due to the effect of state income taxes, changes in valuation allowances, research and development ("R&D") credits, and other permanent differences. The quarterly rate can also be affected by the proportional impacts 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,	
	2016	2015	2016	2015
	(in thousands)			
Current portion of income tax expense (benefit):				
Federal	$—	$—	$—	$—
State	24	(8,308)	265	2,092
Deferred portion of income tax expense (benefit)	(23,756)	4,168	(314,770)	(80,388)
Income tax benefit	$(23,732)	$(4,140)	$(314,505)	$(78,296)
Effective tax rate	36.7 %	403.5 %	36.1 %	42.2 %

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 or loss from Company activities among multiple state tax jurisdictions. Cumulative effects of state tax rate changes are reflected in the period legislation is enacted.

The Company is generally no longer subject to United States federal or state income tax examinations by tax authorities for years before 2013. During the first quarter of 2016, the Company received an expected $4.9 million refund of tax and interest after the Company and the Internal Revenue Service ("IRS") reached a final agreement on the examination of the Company's 2007 - 2011 tax years. There were no material adjustments to previously reported amounts. During the quarter ended September 30, 2015, the IRS initiated an audit of the tax partnership between the Company and Mitsui E&P Texas LP for the 2013 tax year. The Company has a significant investment in the underlying assets of this tax partnership. The Company received notice during the first quarter of 2016 that the IRS concluded the audit with no adjustments. In accordance with regulations, the Senior Convertible Notes and the capped call transactions, as defined and discussed in Note 5 - Long-Term Debt, were identified during the quarter as an integrated transaction.

Note 5 - Long-Term Debt

Revolving Credit Facility

During 2016, the following amendments have been made to the Company's Fifth Amended and Restated Credit Agreement (the "Credit Agreement") with its lenders:

- On April 8, 2016, as part of the regular, semi-annual borrowing base redetermination process, the Company entered into a Sixth Amendment to the Credit Agreement, which reduced the Company's borrowing base to $1.25 billion. This expected reduction was primarily due to a decline in commodity prices, which resulted in a decrease in the Company's proved reserves as of December 31, 2015. The amendment also reduced the aggregate lender commitments to $1.25 billion, and changed the required percentage of oil and gas properties subject to a mortgage to at least 90 percent of the total PV-9 of the Company's proved oil and gas properties evaluated in the most recent reserve report. Further, this amendment revised certain of the Company's covenants under the Credit Agreement and modified the borrowing base utilization grid, as discussed below. The Company incurred approximately $3.1 million in deferred financing costs associated with this amendment to the Credit Agreement.
- On August 8, 2016, the Company entered into a Seventh Amendment to the Credit Agreement to allow for capped call transactions.
- Upon issuing the Senior Convertible Notes and 2026 Notes (as defined and discussed below) during the third quarter of 2016, the Company's borrowing base and aggregate lender commitments were reduced from $1.25 billion to $1.1 billion.
- On September 30, 2016, the Company entered into an Eighth Amendment to the Credit Agreement. Pursuant to the amendment, and as part of the regular, semi-annual borrowing base redetermination process, the Company's borrowing base was increased to $1.35 billion and aggregate lender commitments increased to $1.25 billion. This increase was primarily due an increase in commodity prices and the value of the proved reserves associated with the Rock Oil Acquisition. The borrowing base increase became effective upon the closing of the Rock Oil Acquisition on October 4, 2016.

The Credit Agreement, as amended, provides for a maximum loan amount of $2.5 billion and has a maturity date of December 10, 2019. The borrowing base redetermination process considers the value of both the Company's (a) proved oil and gas properties reflected in the Company's most recent reserve report and (b) commodity derivative contracts, each as determined by the Company's lender group. The next scheduled redetermination date is April 1, 2017.

The Company must comply with certain financial and non-financial covenants under the terms of the Credit Agreement, including covenants limiting dividend payments and requiring the Company to maintain certain financial ratios, as defined by the Credit Agreement. Financial covenants under the Credit Agreement require, as of the last day of each of the Company's fiscal quarters, the Company's (a) ratio of senior secured debt to 12-month trailing adjusted EBITDAX to be not more than 2.75 to 1.0; (b) adjusted current ratio to be not less than 1.0 to 1.0; and (c) ratio of 12-month trailing adjusted EBITDAX to interest expense to be not less than 2.0 to 1.0. The Company was in compliance with all financial and non-financial covenants under the Credit Agreement as of September 30, 2016, and through the filing date of this report.

Interest and commitment fees are accrued based on a borrowing base utilization grid set forth in the Credit Agreement. Eurodollar loans accrue interest at the London Interbank Offered Rate plus the applicable margin from the utilization table below, and Alternate Base Rate ("ABR") and swingline loans accrue interest at the prime rate, plus the applicable margin from the utilization table below. Commitment fees are accrued on the unused portion of the aggregate lender commitment amount and are included in interest expense in the accompanying statements of operations. The borrowing base utilization grid under the Credit Agreement is as follows:

Borrowing Base Utilization Grid

Borrowing Base Utilization Percentage	<25%	≥25% <50%	≥50% <75%	≥75% <90%	≥90%
Eurodollar Loans	1.750%	2.000%	2.250%	2.500%	2.750%
ABR Loans or Swingline Loans	0.750%	1.000%	1.250%	1.500%	1.750%
Commitment Fee Rate	0.300%	0.300%	0.350%	0.375%	0.375%

The following table presents the outstanding balance, total amount of letters of credit outstanding, and available borrowing capacity under the credit facility as of October 26, 2016, September 30, 2016, and December 31, 2015:

	As of October 26, 2016	As of September 30, 2016	As of December 31, 2015
	(in thousands)		
Credit facility balance [1]	$—	$—	$202,000
Letters of credit [2]	200	200	200
Available borrowing capacity	1,249,800	1,106,675	1,297,800
Total aggregate lender commitment amount	$1,250,000	$1,106,875	$1,500,000

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[1] Unamortized deferred financing costs attributable to the credit facility are presented as a component of other noncurrent assets on the accompanying balance sheets and thus are not deducted from the credit facility balance.
[2] Letters of credit outstanding reduce the amount available under the credit facility on a dollar-for-dollar basis.

Senior Notes

The Company's Senior Notes consist of 6.50% Senior Notes due 2021, 6.125% Senior Notes due 2022, 6.50% Senior Notes due 2023, 5.0% Senior Notes due 2024, 5.625% Senior Notes due 2025, and 6.75% Senior Notes due 2026 (collectively referred to as "Senior Notes"). The Senior Notes, net of unamortized deferred financing costs line on the accompanying balance sheets as of September 30, 2016, and December 31, 2015, consisted of the following:

	As of September 30, 2016			As of December 31, 2015		
	Senior Notes	Unamortized Deferred Financing Costs	Senior Notes, Net of Unamortized Deferred Financing Costs	Senior Notes	Unamortized Deferred Financing Costs	Senior Notes, Net of Unamortized Deferred Financing Costs
	(in thousands)					
6.50% Senior Notes due 2021	$346,955	$ 3,547	$ 343,408	$350,000	$ 4,106	$ 345,894
6.125% Senior Notes due 2022	561,796	7,274	554,522	600,000	8,714	591,286
6.50% Senior Notes due 2023	394,985	4,618	390,367	400,000	5,231	394,769
5.0% Senior Notes due 2024	500,000	6,763	493,237	500,000	7,455	492,545
5.625% Senior Notes due 2025	500,000	7,845	492,155	500,000	8,524	491,476
6.75% Senior Notes due 2026	500,000	8,291	491,709	—	—	—
Total	$2,803,736	$ 38,338	$ 2,765,398	$2,350,000	$ 34,030	$ 2,315,970

The Senior Notes are unsecured senior obligations and rank equal in right of payment with all of the Company's existing and any future unsecured senior debt, and are senior in right of payment to any future subordinated debt. There are no subsidiary guarantors of the Senior Notes. The Company is subject to certain covenants under the indentures governing the Senior Notes that limit the Company's ability to incur additional indebtedness, issue preferred stock, and make restricted payments, including dividends; however, the first $6.5 million of dividends paid each year are not restricted by the restricted payment covenant. The Company was in compliance with all covenants under its Senior Notes as of September 30, 2016, and through the filing date of this report. The Company may redeem some or all of its Senior Notes prior to their maturity at redemption prices based on a premium, plus accrued and unpaid interest as described in the indentures governing the Senior Notes.

During the first quarter of 2016, the Company repurchased in open market transactions a total of $46.3 million in aggregate principal amount of its 6.50% Senior Notes due 2021, 6.125% Senior Notes due 2022, and 6.50% Senior Notes due 2023 for a settlement amount of $29.9 million, excluding interest, which resulted in a net gain on extinguishment of debt of approximately $15.7 million. This amount includes a gain of $16.4 million associated with the discount realized upon repurchase, which was partially offset by approximately $700,000 related to the acceleration of unamortized deferred financing costs. The Company accounted for the repurchases under the extinguishment method of accounting. The Company canceled all repurchased Senior Notes upon cash settlement.

2026 Notes

On September 12, 2016, the Company issued $500.0 million in aggregate principal amount of 6.75% Senior Notes due September 15, 2026, at par (the “2026 Notes”). The Company received net proceeds of $491.6 million after deducting paid and accrued fees of $8.4 million, which are being amortized as deferred financing costs over the life of the 2026 Notes. The net proceeds were used to partially fund the Rock Oil Acquisition that closed on October 4, 2016.

Senior Convertible Notes

On August 12, 2016, the Company issued $172.5 million in aggregate principal amount of 1.50% Senior Convertible Notes due July 1, 2021 (the “Senior Convertible Notes”). The Senior Convertible 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. The Company received net proceeds of $166.7 million after deducting fees of $5.8 million, of which a portion is being amortized over the life of the Senior Convertible Notes. The net proceeds were used to partially fund the Rock Oil Acquisition that closed on October 4, 2016.

The Senior Convertible Notes mature on July 1, 2021, unless earlier repurchased or converted. Holders may convert their Senior Convertible Notes at their option at any time prior to January 1, 2021, only under the following circumstances: (1) during any calendar quarter (and only during such calendar quarter) commencing after the calendar quarter ending on September 30, 2016, if the last reported sale price of the Company’s common stock for at least 20 trading days (whether or not consecutive) during a period of 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter is greater than or equal to 130% of the conversion price on each applicable trading day; (2) during the five business day period after any five consecutive trading day period (the “measurement period”) in which the trading price (as defined in the indenture) per $1,000 principal amount of Notes for each trading day of the measurement period was less than 98% of the product of the last reported sale price of the Company’s common stock and the conversion rate on each such trading day; or (3) upon the occurrence of specified corporate events. On or after January 1, 2021, until the maturity date, holders may convert their Senior Convertible Notes at any time, regardless of the foregoing circumstances. The Company may not redeem the Senior Convertible Notes prior to the maturity date. Upon conversion, the Senior Convertible Notes may be settled, at the Company’s election, in shares of the Company’s common stock, cash, or a combination of cash and common stock. Holders may convert their notes based on a conversion rate of 24.6914 shares of the Company’s common stock per $1,000 principal amount of the Senior Convertible Notes, which is equal to an initial conversion price of approximately $40.50 per share, subject to adjustment.

The Company has initially elected a net-settlement method to satisfy its conversion obligation, which allows the Company to settle the principal amount of the Senior Convertible Notes in cash and to settle the excess conversion value in shares, as well as cash in lieu of fractional shares. The Senior Convertible Notes were not convertible at the option of holders as of September 30, 2016, or through the filing date of this report. Notwithstanding the inability to convert, the if-converted value of the Senior Convertible Notes as of September 30, 2016, did not exceed the principal amount.

In accounting for the Senior Convertible Notes at issuance, the Company allocated proceeds from the Senior Convertible Notes into debt and equity components according to the authoritative accounting guidance for convertible debt instruments that may be fully or partially settled in cash upon conversion. The initial carrying amount of the debt component, which approximates its fair value, was estimated by using an interest rate for nonconvertible debt with terms similar to the Senior Convertible Notes. The effective interest rate used was 7.25 percent. The excess of the principal amount of the Senior Convertible Notes over the fair value of the debt component was recorded as a debt discount and a corresponding increase in additional paid-in capital. The Company incurred transaction costs of $5.8 million relating to the issuance of the Senior Convertible Notes, which were allocated between the debt and equity components in proportion to their determined fair value amounts. The debt discount and debt issuance costs are amortized to the carrying value of the Senior Convertible Notes as interest expense through the maturity date of July 1, 2021. Upon issuance of the Senior Convertible Notes, the Company recorded $132.3 million as long-term debt and $40.2 million as additional paid-in capital in stockholders' equity in the accompanying balance sheets.

The net carrying amount of the liability component of the Senior Convertible Notes, as reflected on the accompanying balance sheets, consisted of the following as of September 30, 2016:

	As of September 30, 2016 (in thousands)
Principal amount of Senior Convertible Notes	$ 172,500
Original debt discount due to allocation of proceeds to equity	(40,217)
Accumulated amortization of debt discount	953
Unamortized deferred financing costs	(4,311)
Net carrying amount	$ 128,925

If the Company undergoes a fundamental change, holders of the Senior Convertible Notes may require the Company to repurchase for cash all or any portion of their notes at a fundamental change repurchase price equal to 100% of the principal amount of the Senior Convertible Notes to be repurchased, plus accrued and unpaid interest. The indenture governing the Senior Convertible Notes contains customary events of default with respect to the Senior Convertible Notes, including that upon certain events of default, the Trustee by notice to the Company, or the holders of at least 25% in principal amount of the outstanding Senior Convertible Notes by notice to the Company, may declare 100% of the principal and accrued and unpaid interest, if any, due and payable immediately. In case of certain events of bankruptcy, insolvency or reorganization involving the Company or a significant subsidiary, 100% of the principal and accrued and unpaid interest on the Senior Convertible Notes will automatically become due and payable.

The Company is subject to certain covenants under the indenture governing the Senior Convertible Notes and was in compliance with all covenants as of September 30, 2016, and through the filing date of this report.

Capped Call Transactions

In connection with the issuance of the Senior Convertible Notes, the Company entered into capped call transactions with affiliates of the underwriters of such issuance. The aggregate cost of the capped call transactions was approximately $24.2 million. The capped call transactions are generally expected to reduce the potential dilution upon conversion of the Senior Convertible Notes and/or partially offset any cash payments the Company is required to make in excess of the principal amount of converted Senior Convertible Notes in the event that the market price per share of the Company’s common stock, as measured under the terms of the capped call transactions (“market price per share”), is greater than the strike price of the capped call transactions, which initially corresponds to the approximate $40.50 per share conversion price of the Senior Convertible Notes and is subject to anti-dilution adjustments substantially similar to those applicable to the conversion rate of the Senior Convertible Notes. The cap price of the capped call transactions will initially be $60.00 per share, and is subject to certain adjustments under the terms of the capped call transactions. If, however, the market price per share exceeds the cap price of the capped call transactions, there would be dilution and/or there would not be an offset of such potential cash payments, in each case, to the extent that such market price per share exceeds the cap price of the capped call transactions.

The Company evaluated the capped call transactions under authoritative accounting guidance and determined that they should be accounted for as separate transactions and classified as equity instruments with no recurring fair value measurement recorded.

Note 6 - Commitments and Contingencies

Commitments

There were no material changes in commitments during the first nine months of 2016, except as discussed below. Please refer to Note 6 - Commitments and Contingencies in the Company's 2015 Form 10-K for additional discussion.

During the second quarter of 2016, the Company entered into a water disposal agreement in the Company's operated Eagle Ford shale program. Under the agreement, the Company is committed to deliver 25.4 MMBbl of water for treatment through 2026. In the event that the Company does not deliver any volumes under this agreement, the Company's aggregate undiscounted deficiency payments would be approximately $23.0 million. This commitment will become effective upon the constructed pipeline becoming operational, which is expected to be in the fourth quarter of 2016.

During 2016, the Company renegotiated the terms of certain drilling rig contracts to provide flexibility concerning the timing of activity and payment. For the three and nine months ended September 30, 2016, the Company incurred $1.1 million and $8.7 million, respectively, of expenses related to the early termination of drilling rig contracts or fees incurred for rigs placed on standby, which are recorded in the other operating expenses line item in the accompanying statements of operations. For the three and nine months ended September 30, 2015, the Company incurred drilling rig termination and standby fees of $2.2 million and $8.1 million, respectively. As of September 30, 2016, the Company had drilling rig commitments totaling $20.0 million through 2018. Early termination of these contracts as of September 30, 2016, would result in termination penalties of $15.1 million, which would be in lieu of paying the remaining $20.0 million commitment. Additionally, the Company entered into drilling rig agreements to begin operating two rigs in the Midland Basin in the fourth quarter of 2016, neither of which has a material long-term commitment.

During the first quarter of 2016, the Company entered into amendments to certain oil gathering and gas gathering agreements related to its outside-operated Eagle Ford shale assets, neither of which previously had a minimum volume commitment, in order to obtain more favorable rates and terms. Under these amended agreements, as of September 30, 2016, the Company is committed to deliver 290 Bcf of natural gas and 38 MMBbl of oil through 2034. In the event that the Company delivers no product under these amended agreements, the Company’s aggregate undiscounted deficiency payments would be approximately $333.2 million at September 30, 2016. However, because the Company owns a partial ownership interest in the gathering systems used to provide the services under these agreements, the Company is entitled to receive its share of operating income generated by the systems, and thus would expect to receive approximately $235.2 million if the $333.2 million shortfall payment was required. The Company’s outside-operated Eagle Ford shale assets, subject to this commitment and other material throughput commitments, are held for sale as of September 30, 2016.

During the first quarter of 2016, the Company entered into an amendment to a gas gathering agreement related to its operated Eagle Ford shale assets, which reduced the Company’s volume commitment amount as of December 31, 2015, by 829 Bcf, and reduced the aggregate undiscounted deficiency payments, in the event no product is delivered, by $118.2 million through 2021.

As of September 30, 2016, the Company had total gas, oil, and NGL gathering, processing, and transportation throughput commitments with various third parties that require delivery of a minimum amount of 1,556 Bcf of natural gas, 69 MMBbl of crude oil, and 13 MMBbl of natural gas liquids through 2034. If the Company delivers no product, the aggregate undiscounted deficiency payments total approximately $1.0 billion through 2034, prior to considering the $235.2 million of operating income the Company would expect to receive if certain payments were required as discussed above.

As of the filing date of this report, the Company does not expect to incur any material shortfalls with regard to its gas, oil, and NGL gathering, processing, and transportation throughput and water disposal commitments.

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 the amount can be reasonably estimated. 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. As of September 30, 2016, the Company had $2.7 million accrued for estimated exposure related to potential claims for payment of royalties on certain Federal oil and gas leases. Although the Company believes that it has properly estimated its potential exposure with respect to these claims based on various contracts, laws and regulations, administrative rulings, and interpretations thereof, adjustments could be required as new interpretations and regulations arise.

Note 7 - Compensation Plans

Equity Incentive Compensation Plan

As of September 30, 2016, 5.5 million shares of common stock remained available for grant under the Company's Equity Incentive Compensation Plan.

Performance Share Units Under the Equity Incentive Compensation Plan

The Company grants performance share units ("PSUs") to eligible employees as 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 primarily 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, 2016, and 2015, was $2.3 million and $2.4 million, respectively, and $8.2 million and $7.4 million for the nine months ended September 30, 2016, and 2015, respectively. As of September 30, 2016, there was $18.9 million of total unrecognized compensation expense related to unvested PSU awards, which is being amortized through 2019.

A summary of the status and activity of non-vested PSUs for the nine months ended September 30, 2016, is presented in the following table:

	PSUs [1]	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year	626,328	$ 61.81
Granted	447,971	$ 26.56
Vested	(129,422)	$ 64.19
Forfeited	(99,414)	$ 57.43
Non-vested at end of quarter	845,463	$ 43.29

(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 nine months ended September 30, 2016, the Company granted 447,971 PSUs with a fair value of $11.9 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 this period, the Company settled PSUs that were granted in 2013, which earned a 0.2 times multiplier, by issuing 30,061 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, 14,809 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 primarily within general and administrative expense and exploration expense over the vesting periods of the award.

Total compensation expense recorded for RSUs was $2.8 million and $4.1 million for the three months ended September 30, 2016, and 2015, respectively, and $9.3 million and $9.9 million for the nine months ended September 30, 2016, and 2015, respectively. As of September 30, 2016, there was $17.8 million of total unrecognized compensation expense related to unvested RSU awards, which is being amortized through 2019.

A summary of the status and activity of non-vested RSUs for the nine months ended September 30, 2016, is presented in the following table:

	RSUs	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year	543,737	$ 55.01
Granted	417,065	$ 28.08
Vested	(240,233)	$ 58.08
Forfeited	(79,393)	$ 46.32
Non-vested at end of quarter	641,176	$ 37.42

During the nine months ended September 30, 2016, as part of its regular annual long-term equity compensation program, the Company granted 417,065 RSUs with a fair value of $11.7 million. These RSUs will vest one-third of the total grant on each of the next three anniversary dates of the grant. Also, during the nine months ended September 30, 2016, the Company released 240,233 RSUs that related to awards granted in previous years. The Company and the majority of grant participants mutually agreed to net share settle a portion of the awards to cover income and payroll tax withholdings as provided for in the plan document and award agreements. As a result, the Company issued 168,395 net shares of common stock. The remaining 71,838 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon delivery of the shares underlying those RSUs.

Director Shares

During the nine months ended September 30, 2016, and 2015, the Company issued 53,473 and 37,950 shares, respectively, of its common stock to its non-employee directors, under the Company’s Equity Incentive Compensation Plan and recorded compensation expense of $1.2 million and $1.4 million, respectively.

Beginning with the awards granted in 2016, all shares issued to non-employee directors fully vest on December 31st of the year granted.

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 percent 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 of 1986, as amended (“IRC”). The Company had 808,854 shares available for issuance under the ESPP as of September 30, 2016. There were 140,853 and 96,285 shares issued under the ESPP during the nine months ended September 30, 2016, and 2015, respectively, and the Company received $2.4 million and $3.2 million, respectively, in cash through payroll deductions. The Company recorded compensation expense of $1.7 million in each of the nine months ended September 30, 2016, and 2015. 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 Net Profits Plan for the nine months ended September 30, 2016, totaled $26.8 million, which included accrued payments of $21.6 million resulting from the divestitures of properties subject to the Net Profits Plan in the third quarter of 2016. Payments related to divested properties are accounted for as a reduction in the net gain on divestiture activity line item in the accompanying statement of operations. Cash payments made or accrued under the Net Profits Plan for the nine months ended September 30, 2015, totaled $7.4 million, which included payments of $3.8 million resulting from the divestitures of the Company's Mid-Continent properties subject to the Net Profits Plan in the second quarter of 2015.

Note 8 - Pension Benefits

Pension Plans

The Company has a non-contributory defined benefit pension plan covering substantially all of its employees who joined the Company prior to January 1, 2015, and 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"). The Company froze the Pension Plans to new participants, effective as of December 31, 2015. Employees participating in the Pension Plans as of December 31, 2015, 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,	
	2016	2015	2016	2015
	(in thousands)			
Service cost	$2,050	$1,989	$6,150	$5,963
Interest cost	727	624	2,181	1,872
Expected return on plan assets that reduces periodic pension cost	(559)	(546)	(1,677)	(1,637)
Amortization of prior service cost	4	4	13	13
Amortization of net actuarial loss	396	371	1,187	1,114
Net periodic benefit cost	$2,618	$2,442	$7,854	$7,325

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 $11.0 million to the Pension Plans during the nine months ended September 30, 2016.

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 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 shares into which the Senior Convertible Notes are convertible. The treasury stock method is used to measure the dilutive impact of these stock awards and the Senior Convertible Notes.

PSUs represent the right to receive, upon settlement of the PSUs after the completion of the three-year performance period, a number of shares of the Company's common stock that may range from zero to two times 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.

On August 12, 2016, the Company issued $172.5 million in aggregate principal amount of Senior Convertible Notes. Upon conversion, the Senior Convertible Notes may be settled, at the Company's election, in shares of the Company's common stock, cash, or a combination of cash and common stock. The Company has initially elected a net-settlement method to satisfy its conversion obligation, which allows the Company to settle the principal amount of the Senior

Convertible Notes in cash and to settle the excess conversion value in shares, as well as cash in lieu of fractional shares. However, the Company has not made this a formal legal irrevocable election and thereby reserves the right to settle the Senior Convertible Notes in any manner allowed under the indenture as business conditions warrant. For accounting purposes, the treasury stock method is used to measure the potential dilutive impact of shares associated with this conversion feature. Shares of the Company’s common stock traded at an average closing price below the $40.50 conversion price for the three months ended September 30, 2016. In connection with the offering of the Senior Convertible Notes, the Company entered into capped call transactions with affiliates of the underwriters that would effectively prevent dilution upon settlement up to the $60.00 cap price. The capped call transactions are not reflected in diluted net income per share as they will always be anti-dilutive. Please refer to Note 5 - Long-Term Debt for additional discussion.

When the Company recognizes a loss from continuing operations, as was the case for the three and nine months ended September 30, 2016, and 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. The following table details the weighted-average anti-dilutive securities for the periods presented:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in thousands)			
Weighted-average common shares excluded from diluted earnings per share due to their anti-dilutive effect:				
Unvested RSUs and contingent PSUs	506	—	193	380

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,	
	2016	2015	2016	2015
	(in thousands, except per share amounts)			
Net income (loss)	$(40,907)	$3,114	$(556,798)	$(107,452)
Basic weighted-average common shares outstanding	78,468	67,961	71,574	67,638
Add: dilutive effect of unvested RSUs and contingent PSUs	—	158	—	—
Diluted weighted-average common shares outstanding	78,468	68,119	71,574	67,638
Basic net income (loss) per common share	$(0.52)	$0.05	$(7.78)	$(1.59)
Diluted net income (loss) per common share	$(0.52)	$0.05	$(7.78)	$(1.59)

Subsequent to September 30, 2016, the Company entered into definitive purchase agreements for the QStar Acquisition expected to close in mid-December 2016, which will be partially funded by a private issuance of approximately 13.4 million shares of common stock. Please refer to Note 13 - Equity for additional discussion.

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 consist of swap and collar arrangements for oil, gas, and NGLs. 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 arrangements, the Company receives the difference between an agreed upon index and the floor price if the index price is below the floor price. The Company pays the difference between the agreed upon 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.

As of September 30, 2016, the Company had commodity derivative contracts outstanding through the second quarter of 2020 as summarized in the tables below. During the three months ended March 31, 2016, the Company restructured certain of its gas derivative contracts by buying fixed price volumes to offset existing 2018 and 2019 fixed price swap contracts totaling 55.0 million MMBtu. The Company then entered into new 2017 fixed price swap contracts totaling 38.6 million MMBtu with a contract price of $4.43 per MMBtu. No cash or other consideration was included as part of the restructuring.

Subsequent to September 30, 2016, the Company entered into derivative fixed price swap contracts through the first quarter of 2019 for a total of 5.4 million MMBtu of gas production at contract prices ranging from $3.15 to $3.46 per MMBtu, and derivative fixed price swap contracts through the fourth quarter of 2019 for 4.1 million Bbls of NGL production at contract prices ranging from $13.02 per Bbl to $47.67 per Bbl. Additionally, subsequent to September 30, 2016, the Company entered into derivative collar contracts through the fourth quarter of 2019 for a total of 3.3 million Bbls of oil production with contract floor prices of $50.00 per Bbl and contract ceiling prices ranging from $58.18 to $61.55 per Bbl.

The following tables summarize the approximate volumes and average contract prices of contracts the Company had in place as of September 30, 2016:

Oil Swaps

Contract Period	NYMEX WTI Volumes	Weighted-Average Contract Price
	(MBbls)	(per Bbl)
Fourth quarter 2016	2,249	$ 59.03
2017	5,612	$ 46.46
Total	7,861	

Oil Collars

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(MBbls)	(per Bbl)	(per Bbl)
Fourth quarter 2016	881	$ 40.00	$ 51.52
2017	2,463	$ 45.00	$ 54.09
Total	3,344		

Natural Gas Swaps

Contract Period	Sold Volumes	Weighted-Average Contract Price	Purchased Volumes	Weighted-Average Contract Price	Net Volumes
	(BBtu)	(per MMBtu)	(BBtu)	(per MMBtu)	(BBtu)
Fourth quarter 2016	26,700	$ 3.34	—	$ —	26,700
2017	99,549	$ 3.94	—	$ —	99,549
2018	57,970	$ 3.70	(30,606)	$ 4.27	27,364
2019	24,415	$ 4.34	(24,415)	$ 4.34	—
Total*	208,634		(55,021)		153,613

*Total net volumes of natural gas swaps are comprised of IF El Paso Permian (1%), IF HSC (96%), and IF NNG Ventura (3%).

NGL Swaps

Contract Period	OPIS Purity Ethane Mont Belvieu			OPIS Propane Mont Belvieu Non-TET			OPIS Normal Butane Mont Belvieu Non-TET			OPS Isobutane Mont Belvieu Non-TET		
	Volumes (MBbls)	Weighted-Average Contract Price (per Bbl)		Volumes (MBbls)	Weighted-Average Contract Price (per Bbl)		Volumes (MBbls)	Weighted-Average Contract Price (per Bbl)		Volumes (MBbls)	Weighted-Average Contract Price (per Bbl)	
Fourth quarter 2016	687	$	8.71	792	$	18.53	226	$	22.91	182	$	23.25
2017	3,062	$	8.92	1,530	$	20.78	—	$	—	—	$	—
2018	2,435	$	10.18	593	$	21.60	—	$	—	—	$	—
2019	1,200	$	10.92	—	$	—	—	$	—	—	$	—
2020	539	$	11.13	—	$	—	—	$	—	—	$	—
Total	7,923			2,915			226			182		

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 $61.1 million as of September 30, 2016, and a net asset of $488.4 million as of December 31, 2015.

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

	As of September 30, 2016			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity contracts	Current assets	$109,818	Current liabilities	$51,059
Commodity contracts	Noncurrent assets	107,029	Noncurrent liabilities	104,705
Derivatives not designated as hedging instruments		$216,847		$155,764

	As of December 31, 2015			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity contracts	Current assets	$367,710	Current liabilities	$ 8
Commodity contracts	Noncurrent assets	120,701	Noncurrent liabilities	—
Derivatives not designated as hedging instruments		$488,411		$ 8

Offsetting of Derivative Assets and Liabilities

As of September 30, 2016, and December 31, 2015, all derivative instruments held by the Company were subject to master netting arrangements with 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.

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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, 2016	Derivative Assets As of December 31, 2015	Derivative Liabilities As of September 30, 2016	Derivative Liabilities As of December 31, 2015
	(in thousands)			
Gross amounts presented in the accompanying balance sheets	$216,847	$ 488,411	$(155,764)	$ (8)
Amounts not offset in the accompanying balance sheets	(136,358)	(8)	136,358	8
Net amounts	$80,489	$ 488,403	$(19,406)	$ —

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, 2016	For the Three Months Ended September 30, 2015	For the Nine Months Ended September 30, 2016	For the Nine Months Ended September 30, 2015
	(in thousands)			
Derivative settlement (gain) loss:				
Oil contracts	$(49,241)	$(90,493)	$(221,397)	$(270,622)
Gas contracts [1]	(10,096)	(19,167)	(82,588)	(92,279)
NGL contracts	1,841	(4,035)	(2,249)	(24,818)
Total derivative settlement gain	$(57,496)	$(113,695)	$(306,234)	$(387,719)
Total derivative (gain) loss:				
Oil contracts	$(733)	$(131,728)	$49,608	$(138,839)
Gas contracts	(14,006)	(66,538)	24,460	(142,807)
NGL contracts	(13,298)	(13,987)	47,018	(3,845)
Total derivative (gain) loss:	$(28,037)	$(212,253)	$121,086	$(285,491)

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

Credit Related Contingent Features

As of September 30, 2016, 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 Sixth Amendment to the Credit Agreement changed the required percentage of oil and gas properties subject to a mortgage to at least 90 percent of the total PV-9 of the Company's proved oil and gas properties evaluated in the most recent reserve report.

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 summarizes 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, 2016:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives [1]	$ —	$ 216,847	$ —
Liabilities:			
Derivatives [1]	$ —	$ 155,764	$ —
Net Profits Plan [1]	$ —	$ —	$ 1,162

[1] This represents a financial asset or liability that is measured at fair value on a recurring basis.

The following table summarizes the Company's assets and liabilities that are measured at fair value in the accompanying balance sheets and where they were classified within the fair value hierarchy as of December 31, 2015:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives [1]	$ —	$ 488,411	$ —
Total property and equipment, net [2]	$ —	$ —	$ 124,813
Liabilities:			
Derivatives [1]	$ —	$ 8	$ —
Net Profits Plan [1]	$ —	$ —	$ 7,611

[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.

Proved and Unproved Oil and Gas Properties and Other Property and Equipment

Total property and equipment, net, measured at fair value within the accompanying balance sheets totaled $124.8 million as of December 31, 2015. None of the Company's property and equipment, net, was measured at fair value in the accompanying balance sheets as of September 30, 2016.

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 representative of the current operating environment, as selected by the Company's management. The calculation of the discount rates are based on the best information available and were estimated to be 10 percent to 15 percent based on the reservoir specific weightings of future estimated proved and unproved cash flows as of September 30, 2016, and December 31, 2015. The Company believes the discount rates are representative of current market conditions and take into account estimates of future cash payments, reserve categories, 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 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. Impairments on proved properties during the nine months ended September 30, 2016, totaled $277.8 million and related primarily to the decline in proved and risk-adjusted probable and possible reserve expected cash flows for the Company's outside-operated Eagle Ford shale assets, driven by commodity price declines during the first quarter of 2016. The Company recorded impairment of proved oil and gas properties expense of $468.7 million for the year ended December 31, 2015, due to the decline in proved and risk-adjusted probable and possible reserve expected cash flows, driven by commodity price declines and were recorded mainly in the Company's east Texas and Powder River Basin programs with smaller impacts on other legacy and non-core assets in the Rocky Mountain region.

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. Abandonment and impairment expense on unproved properties was $5.9 million for the nine months ended September 30, 2016, and $78.6 million for the year ended December 31, 2015. In both periods, abandonment and impairment expense resulted from lease expirations and acreage the Company no longer intended to develop in light of changes in drilling plans in response to the decline in commodity prices.

Other property and equipment costs are evaluated for impairment and reduced to fair value when there is an indication the carrying costs may not be recoverable. Fair value of other property and equipment is valued using an income valuation technique or market approach depending on the quality of information available to support management's assumptions and the circumstances. The valuation includes consideration of the proved and unproved assets supported by the property and equipment, future cash flows associated with the assets, and fixed costs necessary to operate and maintain the assets. The Company recorded impairment of other property and equipment expense of $49.4 million for the year ended December 31, 2015, on the Company's gathering system assets in east Texas. These assets were impaired in conjunction with the impairment of the associated proved and unproved properties, which the Company no longer intended to develop and made the subsequent decision to sell.

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. There were no assets held for sale recorded at fair value as of September 30, 2016, or December 31, 2015. Please refer to Note 3 – Assets Held for Sale, Divestitures and Acquisitions.

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.

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 using a discount rate of 10 percent, and is intended to represent the Company's best estimate of the present value of expected future payments under the Net Profits Plan. The estimate is highly dependent on commodity prices, cost assumptions, discount rates, and overall market conditions. Pricing assumptions used are five one-year strip prices with the fifth year's pricing then carried out indefinitely with adjustments made 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 estimate is volatile from period to period due to fluctuations that occur in the oil, gas, and NGL commodity markets. Due to divestitures of assets subject to the Net Profits Plan in recent years, the liability has been significantly reduced.

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, 2016 (in thousands)
Beginning balance	$ 7,611
Net increase in liability [1]	20,389
Net settlements [1] [2]	(26,838)
Transfers in (out) of Level 3	—
Ending balance	$ 1,162

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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 in 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 $21.6 million for the nine months ended September 30, 2016, 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 and Senior Convertible Notes measured using Level 1 inputs based on quoted secondary market trading prices. The Senior Notes and Senior Convertible Notes were not presented at fair value on the accompanying balance sheets as of September 30, 2016, or December 31, 2015, as they were recorded at carrying value, net of any unamortized discount and deferred financing costs. Please refer to Note 5 - Long-Term Debt for discussion of the Company's repurchase of a portion of its Senior Notes during the first quarter of 2016 and the bifurcation of the Senior Convertible Notes.

	As of September 30, 2016		As of December 31, 2015	
	Principal Amount	Fair Value	Principal Amount	Fair Value
	(in thousands)			
6.50% Senior Notes due 2021	$346,955	$354,761	$350,000	$262,938
6.125% Senior Notes due 2022	$561,796	$567,414	$600,000	$440,250
6.50% Senior Notes due 2023	$394,985	$400,910	$400,000	$296,000
5.0% Senior Notes due 2024	$500,000	$472,220	$500,000	$334,065
5.625% Senior Notes due 2025	$500,000	$470,000	$500,000	$326,875
6.75% Senior Notes due 2026	$500,000	$506,250	$—	$—
1.50% Senior Convertible Notes due 2021	$172,500	$210,990	$—	$—

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.

Note 12 - Exit and Disposal Costs

In the third quarter of 2016, the Company conducted a company-wide reduction in workforce and announced plans to close the Company's Billings, Montana regional office and relocate certain employees to the Company's corporate office in Denver, Colorado or other Company offices. This decision was made in an effort to reduce future costs and better position the Company for efficient growth in response to prolonged commodity price weakness. The Company expects to incur approximately $8 million of exit and disposal costs related to termination benefits, relocation of certain employees, and other related matters, excluding lease expenses discussed in the next paragraph, all of which will be included in general and administrative expense in the accompanying statements of operations. The majority of these costs are expected to be recorded in 2016 with the remaining costs recorded in early 2017. The Company incurred $2.9 million of exit and disposal costs during the three months ended September 30, 2016.

Additionally, during the third quarter of 2016, the Company announced plans to vacate its office space in Billings, Montana effective November 1, 2016. As of September 30, 2016, the Company was obligated to pay lease costs of approximately $6.5 million over the remaining lease term. Subsequent to September 30, 2016, the Company and its lessor executed an agreement to terminate this lease effective November 11, 2016, and pay a fee of $3.2 million in lieu of the $6.5 million in lease costs.

In conjunction with its Mid-Continent divestitures in 2015, the Company closed its Tulsa, Oklahoma office and incurred $1.0 million and $9.5 million of exit and disposal costs included in general and administrative expense in the accompanying statements of operations for the three and nine months ended September 30, 2015, respectively. The remaining exit and disposal costs were incurred in the fourth quarter of 2015, with the exception of lease expenses discussed in the next paragraph.

Additionally, the Company vacated its office space in Tulsa during the third quarter of 2015 and subsequently subleased its space. As of September 30, 2016, the Company is obligated to pay lease costs of approximately $3.8 million, net of expected income from office space subleased, which will be expensed over the remaining duration of the lease, which expires in 2022.

Note 13 - Equity

On August 12, 2016, the Company completed an underwritten public offering of 18.4 million shares of its common stock at an offering price of $30.00 per share. Net proceeds from the offering totaled $530.9 million, after deducting underwriting discounts and commissions and offering expenses, which the Company used to partially fund the Rock Oil Acquisition that closed subsequent to September 30, 2016. The offering was made pursuant to an effective shelf registration statement on Form S-3 filed with the Securities and Exchange Commission.

Subsequent to September 30, 2016, the Company announced the QStar Acquisition, discussed in Note 3 – Assets Held for Sale, Divestitures and Acquisitions. The Company plans to partially fund the acquisition through a private issuance of $500.0 million of the Company's common stock to the sellers based on the volume-weighted average price for the 30 days prior to the execution of the definitive purchase agreements for the QStar Acquisition of $37.35 per share, or approximately 13.4 million shares.

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 acquisition, exploration, development, and production of oil, gas, and NGLs in onshore North America. Our strategic objective is to profitably 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 we 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.

During 2016, we have focused our capital investments on our development positions in the Permian Basin, Eagle Ford shale, and Bakken/Three Forks resource plays. Subsequent to September 30, 2016, we announced:

- closing the Rock Oil Acquisition in the Midland Basin;
- entering into the QStar Acquisition agreements in the Midland Basin; and
- entering into an agreement to sell our Raven/Bear Den and other assets in the Williston Basin.

We have outlined a straight-forward strategy to focus on expanding our Tier 1 assets in the Permian Basin and developing these assets along with our operated Eagle Ford shale assets. As part of this strategy, we will continue to core up our portfolio, so that we can concentrate our investment dollars in our highest return programs and bring that value forward through accelerated development activity.

In the third quarter of 2016, we had the following financial and operational results:

- Average net daily production for the three months ended September 30, 2016, was 47.2 MBbls of oil, 403.0 MMcf of gas, and 39.5 MBbls of NGLs, for a quarterly equivalent daily production rate of 153.9 MBOE, compared with 174.5 MBOE for the same period in 2015. Please see additional discussion below under Production Results.
- We recorded a net loss of $40.9 million, or $0.52 per diluted share, for the three months ended September 30, 2016, compared with net income of $3.1 million, or $0.05 per diluted share, for the three months ended September 30, 2015. Please refer to Comparison of Financial Results and Trends Between the Three Months and Nine Months Ended September 30, 2016, and 2015, below for additional discussion regarding the components of net income (loss) for each period.
- Costs incurred for oil and gas property acquisitions, exploration and development activities for the three months ended September 30, 2016, totaled $156.5 million, compared with $286.6 million for the same period in 2015. Please refer to Costs Incurred in Oil and Gas Producing Activities below for additional discussion.
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Net cash provided by operating activities for the three months ended September 30, 2016 totaled $158.1 million, compared with $235.3 million for the same period in 2015.

- Adjusted EBITDAX, a non-GAAP financial measure, for the three months ended September 30, 2016, was $205.1 million, compared with $259.4 million for the same period in 2015. 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 the calendar month average of the NYMEX WTI daily contract settlement prices, excluding weekends, during the month of production, 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 2016, as well as the third quarter of 2015:

	For the Three Months Ended		
	September 30, 2016	June 30, 2016	September 30, 2015
Crude Oil (per Bbl):			
Average NYMEX contract monthly price	$44.94	$45.59	$ 46.48
Realized price, before the effect of derivative settlements	$38.81	$39.38	$ 40.03
Effect of oil derivative settlements	$11.34	$17.59	$ 20.02
Natural Gas:			
Average NYMEX monthly settle price (per MMBtu)	$2.81	$1.95	$ 2.75
Realized price, before the effect of derivative settlements (per Mcf)	$2.71	$1.79	$ 2.77
Effect of natural gas derivative settlements (per Mcf)	$0.27	$0.81	$ 0.45
NGLs (per Bbl):			
Average OPIS price [1]	$19.74	$20.04	$ 18.22
Realized price, before the effect of derivative settlements	$16.58	$16.12	$ 15.18
Effect of NGL derivative settlements	$(0.51)	$(0.51)	$ 0.94

(1) 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 continue to be volatile. In addition to supply and demand fundamentals, as a global commodity, the price of oil is affected by real or perceived geopolitical risks in all regions of the world as well as the relative strength of the dollar compared to other currencies. Oil markets continue to be unstable as a result of over-supply. While we have realized production declines in the United States, declines elsewhere in the world are required to balance the market.

Natural gas pricing increased during the third quarter of 2016, largely as a result of demand growth from gas fired power generation and exports exceeding prior expectations. We expect prices to continue to recover due to decreased supply from associated oil drilling and ethane recovery, and from continued demand growth from LNG exports and exports to Mexico. We also expect prices to fluctuate with changes in demand resulting from the weather.

NGL prices have recovered in recent months due to oil and natural gas price recovery, and we expect continued recovery through 2017 as increased demand from export and petrochemical markets grow.

Overall, we expect commodity prices to fluctuate but remain near current levels through the remainder of 2016, and we expect prices to increase in 2017 due to reduced supply and demand increases across all 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 26, 2016, and September 30, 2016:

	As of October 26, 2016	As of September 30, 2016
NYMEX WTI oil (per Bbl)	$ 51.78	$ 50.76
NYMEX Henry Hub gas (per MMBtu)	$ 3.05	$ 3.07
OPIS NGLs (per Bbl)	$ 23.23	$ 22.64

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, the level of capital commitments and long-term obligations we have in place, and our ability to enter into favorable derivative commodity contracts. With our current derivative contracts, we believe we 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 2016 Highlights and Outlook for the Remainder of 2016

Operational Activities. During 2016, we have focused on coring up our portfolio to high-grade assets and building long-term inventory while maintaining a strong balance sheet and preserving liquidity in the current commodity price environment. We expect to incur capital expenditures, excluding asset acquisitions, below adjusted EBITDAX. By concentrating our capital to the highest return programs and operating at peer leading performance levels, we will generate higher company-wide margins, cash flow growth, and value creation for our shareholders going forward.

We expect our capital program for 2016 to be approximately $700 million, of which approximately 85 percent is directed toward drilling and completion activities with the focus on our core development programs in the Permian Basin, operated Eagle Ford shale, and Bakken/Three Forks. This includes added expenditures for drilling and completion activities on our Rock Oil Acquisition acreage, which we expect to be offset by lower drilling and completion costs and realized efficiencies across all of our regions. Conducting safe operations remains a high priority for us, even as we pursue cost saving measures throughout our business.

In our operated Eagle Ford shale program, we began the third quarter of 2016 with one active, operated drilling rig. We dropped this rig during the third quarter of 2016 and used one frac crew through the end of the third quarter. In 2016, we have focused a significant portion of our capital on wells that were drilled but uncompleted at year-end 2015 and drilling wells required to satisfy lease obligations. As of September 30, 2016, we had drilled but not completed 56 gross and net wells in our operated Eagle Ford shale program. We drilled 16 gross and net wells during the first nine months of 2016.

In our outside-operated Eagle Ford shale program, the operator has further slowed its pace of development, and we do not expect any further drilling or completion activity in 2016. Our outside-operated Eagle Ford shale assets, including the associated midstream assets, are held for sale as of September 30, 2016.

In our Bakken/Three Forks program, we ran one active, operated drilling rig during the third quarter of 2016 in Divide County, North Dakota, which we expect to run for the remainder of 2016. As of September 30, 2016, we had drilled but not completed 17 gross wells (14 net) in our operated Bakken/Three Forks program. We drilled 20 gross wells (18 net) during the first nine months of 2016. Subsequent to September 30, 2016, we entered into a definitive agreement to sell our Raven/Bear Den assets for a gross purchase price of $785.0 million, subject to customary purchase price adjustments. The assets to be sold include producing properties and approximately 54,500 net acres, consisting largely of our Raven/Bear Den acreage, and effectively all lease-holdings in the basin outside of our Divide County, North Dakota position.

In our Permian Basin development program, we ran two operated drilling rigs during the third quarter of 2016 where our focus is on developing the Wolfcamp and Spraberry shale intervals on our Sweetie Peck property in Upton County, Texas. As of September 30, 2016, we had drilled but not completed six gross and net wells in our Permian program. We drilled 18 gross and net wells during the first nine months of 2016. Upon closing the Rock Oil Acquisition, we added an operated rig on our acquired Howard County, Texas acreage. We expect to begin running a second rig later in the fourth quarter of 2016. Subsequent to September 30, 2016, we entered into the QStar Acquisition agreements to acquire proved and unproved properties in Howard and Martin Counties, Texas.

In our Powder River Basin program, we added a rig during the third quarter of 2016 for activities under an acquisition and development funding agreement with a third party, under which our costs to drill and complete a specified number of initial wells are being carried by such party.

We will continue to evaluate our drilling and completion activities throughout the remainder of 2016 as we respond to commodity price changes and costs. Please refer to Overview of Liquidity and Capital Resources below for additional discussion concerning how we intend to fund the remainder of our 2016 capital program.

Production Results. The table below provides a regional breakdown of our production for the three and nine months ended September 30, 2016:

	South Texas & Gulf Coast		Rocky Mountain		Permian		Total [1]	
	Three Months Ended	Nine Months Ended	Three Months Ended	Nine Months Ended	Three Months Ended	Nine Months Ended	Three Months Ended	Nine Months Ended
	September 30, 2016		September 30, 2016		September 30, 2016		September 30, 2016	
Oil (MMBbl)	1.4	4.3	2.2	6.5	0.7	1.7	4.3	12.6
Gas (Bcf)	32.9	99.8	2.7	7.9	1.5	4.0	37.1	111.7
NGLs (MMBbl)	3.6	10.4	0.1	0.3	—	—	3.6	10.7
Equivalent (MMBOE)	10.4	31.4	2.7	8.1	1.0	2.4	14.2	41.9
Avg. daily equivalents (MBOE/d)	113.4	114.7	29.8	29.5	10.7	8.7	153.9	152.9
Relative percentage	74 %	75 %	19 %	19 %	7 %	6 %	100 %	100 %

[1] Amounts may not calculate due to rounding.

Production decreased for the three months ended September 30, 2016, compared with the same period in 2015, as a result of our reduction in drilling and completion activity. For the nine months ended September 30, 2016, compared with the same period in 2015, the decline in production was also driven by the divestiture of properties in our Mid-Continent region in the second quarter of 2015. The table below provides a summary of wells completed in our operated programs during the three and nine months ended September 30, 2016.

	For the Three Months Ended		For the Nine Months Ended	
	September 30, 2016			
	Gross	Net	Gross	Net
Eagle Ford shale	25	25	36	36
Bakken/Three Forks	28	26	50	44
Permian Basin	9	9	21	21
Total	62	60	107	101

Please refer to Comparison of Financial Results and Trends Between the Three Months and Nine Months Ended September 30, 2016, and 2015 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, 2016	For the Nine Months Ended September 30, 2016
	(in millions)	
Development costs [1]	$ 128.8	$ 457.7
Exploration costs	22.1	78.1
Acquisitions		
Proved properties	0.6	2.9
Unproved properties [2]	5.0	22.5
Total, including asset retirement obligations [3]	$ 156.5	$ 561.2

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[1] Includes facility costs of $3.6 million and $15.7 million for the three and nine months ended September 30, 2016, respectively.
[2] The three and nine months ended September 30, 2016, includes $4.0 million and $20.8 million, respectively, of unproved properties acquired as part of proved property acquisitions. The remaining amount is leasing activity.
[3] The three and nine months ended September 30, 2016, includes amounts relating to estimated asset retirement obligations of $1.1 million and $3.2 million, respectively, and capitalized interest of $4.5 million and $14.8 million, respectively.

The majority of costs incurred for oil and gas producing activities during 2016 were in the development of our Permian Basin, operated Eagle Ford shale, and Bakken/Three Forks programs. Please refer to Production Results above for discussion on completion activity, and to the section Third Quarter 2016 Highlights and Outlook for the Remainder of 2016 above for discussion on wells that have been drilled but not completed as of September 30, 2016. Additionally, please refer to Overview of Liquidity and Capital Resources below for additional discussion on how we expect to fund our capital program.

Divestiture Activity. During the third quarter of 2016, we closed the divestitures of certain non-core properties in southeast New Mexico and in the Williston and Powder River Basins previously held for sale for total net divestiture proceeds of $165.2 million, as defined in Note 3 – Assets Held for Sale, Divestitures and Acquisitions in Part I, Item I of this report. Additionally, we began the marketing of our outside-operated Eagle Ford shale and Raven/Bear Den assets during the third quarter of 2016.

Raven/Bear Den Divestiture. Subsequent to September 30, 2016, we entered into a definitive agreement for the sale of our Raven/Bear Den assets for a gross purchase price of $785.0 million, subject to customary purchase price adjustments. This transaction is expected to close in early December 2016 with the net proceeds expected to be used to partially fund the QStar Acquisition. These assets were held for sale as of September 30, 2016. The closing of this divestiture is subject to the satisfaction of customary closing conditions, and there can be no assurance that this transaction will close on the expected closing date or at all.

Rock Oil Acquisition. In August 2016, we entered into a purchase agreement with Rock Oil Holdings LLC to acquire all membership interests of JPM EOC Opal, LLC, which owned oil and gas properties in Howard County, Texas. This acquisition closed on October 4, 2016, for an adjusted purchase price of approximately $991.0 million. Proceeds received from asset divestitures and our equity, Senior Convertible Notes, and 2026 Senior Notes offerings during the third quarter of 2016 were used to fund this acquisition. Please refer to Note 3 – Assets Held for Sale, Divestitures and Acquisitions in Part I, Item I of this report for additional discussion.

QStar Acquisition. Subsequent to September 30, 2016, we entered into definitive purchase agreements with QStar and RRP to acquire oil and gas properties in Howard and Martin Counties, Texas. This acquisition is expected to close mid-December 2016, for a purchase price of $1.6 billion, subject to customary purchase price adjustments. We plan to fund the acquisition through proceeds from planned divestitures and borrowings under our credit facility, totaling $1.1 billion in cash, as well as through a private issuance of $500.0 million of our common stock (approximately 13.4 million shares) to the sellers. The closing of these transactions are subject to the satisfaction of customary closing conditions, and there can be no assurance that either of these transactions will close on the expected closing dates or at all. Please refer to Note 3 – Assets Held for Sale, Divestitures and Acquisitions and Note 13 - Equity in Part I, Item I of this report for additional discussion.

Equity Offering. In August 2016, we issued 18.4 million shares of common stock in a public offering for net proceeds of $530.9 million. Please refer to Note 13 - Equity in Part I, Item I of this report for additional discussion.

Senior Convertible Notes. In August 2016, we issued $172.5 million in aggregate principal amount of 1.50% Senior Convertible Notes due 2021 for net proceeds of $166.7 million. In conjunction with this issuance, we paid and accrued $24.2 million for capped call transactions, which are generally expected to reduce the potential dilution upon conversion of the Senior Convertible Notes and/or partially offset any cash payments we are required to make in excess of the principal amount of converted Senior Convertible Notes. Please see Note 5 - Long-Term Debt in Part I, Item I of this report for additional discussion.

2026 Senior Notes. In September 2016, we issued $500.0 million in aggregate principal amount of 6.75% Senior Notes due 2026 and received net proceeds of $491.6 million. Please see Note 5 - Long-Term Debt in Part I, Item I of this report for additional discussion.

Credit Facility Amendment. Subsequent to September 30, 2016, our lenders under the Credit Agreement increased our borrowing base to $1.35 billion and set current aggregate lender commitments at $1.25 billion as part of the regularly scheduled semi-annual redetermination and as a result of closing the Rock Oil Acquisition. Please refer to Note 5 - Long-Term Debt in Part I, Item I of this report for additional discussion.

Financial Results of Operations and Additional Comparative Data

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

	For the Three Months Ended			
	September 30, 2016	June 30, 2016	March 31, 2016	December 31, 2015
	(in millions, except for production data)			
Production (MMBOE)	14.2	14.3	13.4	14.9
Oil, gas, and NGL production revenue	$329.2	$291.1	$211.8	$ 298.7
Oil, gas, and NGL production expense	$152.5	$148.6	$144.5	$ 169.2
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$194.0	$211.0	$214.2	$ 240.0
Exploration	$13.5	$13.2	$15.3	$ 37.9
General and administrative	$32.7	$28.2	$32.2	$ 33.6
Net loss	$(40.9)	$(168.7)	$(347.2)	$ (340.3)

Note: Amounts may not calculate due to rounding.

Selected Performance Metrics:

	For the Three Months Ended			
	September 30, 2016	June 30, 2016	March 31, 2016	December 31, 2015
Average net daily production equivalent (MBOE/d)	153.9	157.2	147.5	162.1
Lease operating expense (per BOE)	$3.29	$3.31	$3.79	$ 3.85
Transportation costs (per BOE)	$6.24	$5.95	$6.06	$ 6.10
Production taxes as a percent of oil, gas, and NGL production revenue	4.5 %	4.6 %	4.2 %	5.1 %
Ad valorem tax expense (per BOE)	$0.21	$0.19	$0.27	$ 0.38
Depletion, depreciation, amortization, and asset retirement obligation liability accretion (per BOE)	$13.70	$14.75	$15.96	$ 16.10
General and administrative (per BOE)	$2.31	$1.97	$2.40	$ 2.26

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, 2016	For the Three Months Ended September 30, 2015	Amount Change Between Periods	Percent Change Between Periods	For the Nine Months Ended September 30, 2016	For the Nine Months Ended September 30, 2015	Amount Change Between Periods	Percent Change Between Periods
Net production volumes [1]								
Oil (MMBbl)	4.3	4.5	(0.2)	(4)%	12.6	14.8	(2.3)	(15)%
Gas (Bcf)	37.1	43.3	(6.3)	(14)%	111.7	133.5	(21.7)	(16)%
NGLs (MMBbl)	3.6	4.3	(0.7)	(16)%	10.7	12.2	(1.5)	(13)%
Equivalent (MMBOE)	14.2	16.1	(1.9)	(12)%	41.9	49.3	(7.4)	(15)%
Average net daily production [1]								
Oil (MBbl per day)	47.2	49.1	(1.9)	(4)%	45.9	54.3	(8.5)	(16)%
Gas (MMcf per day)	403.0	471.1	(68.1)	(14)%	407.8	488.9	(81.1)	(17)%
NGLs (MBbl per day)	39.5	46.8	(7.3)	(16)%	39.0	44.8	(5.8)	(13)%
Equivalent (MBOE per day)	153.9	174.5	(20.6)	(12)%	152.9	180.6	(27.7)	(15)%
Oil, gas, and NGL production revenue (in millions)								
Oil production revenue	$168.6	$180.9	$(12.3)	(7)%	$436.0	$644.1	$(208.1)	(32)%
Gas production revenue	100.4	120.2	(19.8)	(16)%	236.7	358.9	(122.2)	(34)%
NGL production revenue	60.2	65.5	(5.3)	(8)%	159.4	198.2	(38.8)	(20)%
Total	$329.2	$366.6	$(37.4)	(10)%	$832.1	$1,201.2	$(369.1)	(31)%
Oil, gas, and NGL production expense (in millions)								
Lease operating expense	$46.5	$62.0	$(15.5)	(25)%	$144.7	$182.3	$(37.6)	(21)%
Transportation costs	88.4	100.7	(12.3)	(12)%	254.8	295.6	(40.8)	(14)%
Production taxes	14.7	15.4	(0.7)	(5)%	37.0	57.1	(20.1)	(35)%
Ad valorem tax expense	2.9	6.5	(3.6)	(55)%	9.2	19.4	(10.2)	(53)%
Total	$152.5	$184.6	$(32.1)	(17)%	$445.7	$554.4	$(108.7)	(20)%
Realized price (before the effect of derivative settlements)								
Oil (per Bbl)	$38.81	$40.03	$(1.22)	(3)%	$34.69	$43.43	$(8.74)	(20)%
Gas (per Mcf)	$2.71	$2.77	$(0.06)	(2)%	$2.12	$2.69	$(0.57)	(21)%
NGLs (per Bbl)	$16.58	$15.18	$1.40	9%	$14.91	$16.20	$(1.29)	(8)%
Per BOE	$23.25	$22.84	$0.41	2%	$19.87	$24.36	$(4.49)	(18)%
Per BOE Data [1]								
Production costs:								
Lease operating expense	$3.29	$3.86	$(0.57)	(15)%	$3.46	$3.70	$(0.24)	(6)%
Transportation costs	$6.24	$6.27	$(0.03)	—%	$6.08	$5.99	$0.09	2%
Production taxes	$1.04	$0.96	$0.08	8%	$0.88	$1.16	$(0.28)	(24)%
Ad valorem tax expense	$0.21	$0.40	$(0.19)	(48)%	$0.22	$0.39	$(0.17)	(44)%
General and administrative	$2.31	$2.35	$(0.04)	(2)%	$2.22	$2.52	$(0.30)	(12)%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$13.70	$15.19	$(1.49)	(10)%	$14.78	$13.81	$0.97	7%
Derivative settlement gain [2]	$4.06	$7.08	$(3.02)	(43)%	$7.31	$7.86	$(0.55)	(7)%
Earnings per share information								
Basic net income (loss) per common share	$(0.52)	$0.05	$(0.57)	(1,140)%	$(7.78)	$(1.59)	$(6.19)	(389)%
Diluted net income (loss) per common share	$(0.52)	$0.05	$(0.57)	(1,140)%	$(7.78)	$(1.59)	$(6.19)	(389)%

Basic weighted-average common shares outstanding (in thousands)	78,468	67,961	10,507	15	%	71,574	67,638	3,936	6	%
Diluted weighted-average common shares outstanding (in thousands)	78,468	68,119	10,349	15	%	71,574	67,638	3,936	6	%

(1) Amount and percentage changes may not calculate due to rounding.
(2) Derivative settlements for the three and nine months ended September 30, 2016, and 2015, 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 September 30, 2015, include a $15.3 million gain on the early settlement of future contracts as a result of divesting our Mid-Continent assets during the second quarter of 2015. This settlement gain increased our derivative settlement gain by $0.31 per BOE 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, 2016, decreased 12 percent and 15 percent, respectively, compared with the same periods in 2015. The decrease for the three months ended September 30, 2016, was primarily due to our reduced drilling and completion activity throughout 2015 and 2016. For the nine months ended September 30, 2016, the decline in production was also driven by the sale of our Mid-Continent assets during the second quarter of 2015. Overall, we expect our fourth quarter production to decrease from the third quarter of 2016 due to the impact of assets that were divested at the end of the third quarter of 2016, slightly offset by production from the Rock Oil Acquisition assets. Please refer to Comparison of Financial Results and Trends Between the Three Months and Nine Months Ended September 30, 2016, and 2015 below for additional discussion.

Changes in production volumes, revenues, and costs reflect the highly volatile nature of our industry. Our realized price on a per BOE basis for the three months ended September 30, 2016, increased slightly compared with the same period in 2015, as we saw an uplift in commodity prices late in the second quarter of 2016 and throughout the third quarter of 2016. For the nine months ended September 30, 2016, our realized price on a per BOE basis decreased 18 percent compared with the same period in 2015.

Lease operating expense ("LOE") on a per BOE basis decreased 15 percent and six percent for the three and nine months ended September 30, 2016, respectively, compared with the same periods in 2015 due to lower service provider costs and reduced workover activity. We experience volatility in our LOE as a result of the impact industry activity has on service provider costs and seasonality in workover expense. For full-year 2016, we expect LOE on a per BOE basis to be slightly lower than full-year 2015 as a result of lower service provider costs.

Transportation expense on a per BOE basis remained relatively flat for the three and nine months ended September 30, 2016, compared with the same periods in 2015. We sold our Mid-Continent assets during the second quarter of 2015, which resulted in our higher cost Eagle Ford shale assets becoming a larger portion of our total production. As a result of this divestiture, we expect the change in our production mix to result in slightly higher transportation costs on a per BOE basis when comparing full-year 2016 to full-year 2015.

Production taxes on a per BOE basis increased eight percent for the three months ended September 30, 2016, compared with the same period in 2015 resulting from changes in our production mix causing an increase in our rate quarter over quarter. Our production tax rate for the three months ended September 30, 2016, and 2015, was 4.5 percent and 4.2 percent, respectively. For the nine months ended September 30, 2016, production taxes on a per BOE basis decreased 24 percent compared with the same period in 2015 in line with the decrease in production revenues and as a result of a decrease in our production tax rate upon divesting our Mid-Continent properties in the second quarter of 2015. Our production tax rate for the nine months ended September 30, 2016, and 2015, was 4.4 percent and 4.8 percent, respectively. 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 also impact or change the amount of production tax we recognize.

Ad valorem tax expense on a per BOE basis decreased 48 percent and 44 percent for the three and nine months ended September 30, 2016, respectively, compared with the same periods in 2015. The decrease in ad valorem tax expense on a per BOE basis is primarily due to the lower valuation of properties subject to ad valorem taxes in 2016 as a result of declining commodity prices. 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.

General and administrative ("G&A") expense on a per BOE basis decreased two percent and 12 percent for the three and nine months ended September 30, 2016, respectively, compared with the same periods in 2015, as our absolute G&A expense has decreased at a faster rate than the decrease in production volumes. The decrease in G&A expense during 2016 is due largely to lower headcount. This impact was partially offset for the three months ended September 30, 2016, compared with the same period in 2015, by higher exit and disposal costs totaling $2.9 million recorded during the third quarter of 2016 related to the recent workforce reduction. Costs related to exit and disposal activities totaled $9.5 million during the nine months ended September 30, 2015, related to the closure of our Tulsa, Oklahoma office; however, the majority of these costs were recorded in the first six months of 2015, while the exit and disposal costs recorded in 2016 were recorded in the third quarter of 2016. Please refer to Note 12 - Exit and Disposal

Costs in Part I, Item 1 of this report for additional discussion. Overall, we expect G&A expense on a per BOE basis to be lower for the full-year 2016 compared with the full-year 2015 due to lower headcount.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion ("DD&A") expense on a per BOE basis decreased 10 percent for the three months ended September 30, 2016, compared with the same period in 2015, as a result of divesting assets during the third quarter of 2016 that became held for sale during the quarter ended March 31, 2016, as well as our outside-operated Eagle Ford shale and Raven/Bear Den assets becoming held for sale during the third quarter of 2016. DD&A expense on a per BOE basis increased seven percent for the nine months ended September 30, 2016, compared with the same period in 2015 with the third quarter decrease being offset by a general increase in our 2016 DD&A rate due to decreased proved reserve volumes resulting from low commodity prices. Changes in commodity prices impact our proved reserve volumes, and consequently, we would expect a decrease in commodity prices to increase our DD&A rate and an increase in commodity prices to lower our DD&A rate. We expect the planned divestitures of our outside-operated Eagle Ford shale and Raven/Bear Den assets to further reduce our fourth quarter DD&A expense on a per BOE basis compared with the third quarter of 2016, as no DD&A expense will be recorded for these assets while they are held for sale.

Please refer to Comparison of Financial Results and Trends Between the Three Months and Nine Months Ended September 30, 2016, and 2015 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 three and nine months ended September 30, 2016, and for the nine months ended September 30, 2015, we recorded losses from continuing operations and all potentially dilutive shares were anti-dilutive and excluded from the calculation of diluted net loss per common share. Subsequent to September 30, 2016, we entered into a purchase agreement for the QStar Acquisition, which is expected to close in mid-December 2016, and will be partially funded by our private issuance of approximately 13.4 million shares of common stock. This issuance will increase our basic and diluted weighted-average common shares outstanding.

Comparison of Financial Results and Trends Between the Three Months and Nine Months Ended September 30, 2016, and 2015

Oil, gas, and NGL production, revenues, and costs

The following table presents the regional changes in our oil, gas, and NGL production, production revenues, and production costs between the three months ended September 30, 2016, and 2015:

	Average Net Daily Production Increase (Decrease)	Production Revenues Increase (Decrease)	Production Costs Increase (Decrease)
	(MBOE/d)	(in millions)	(in millions)
South Texas & Gulf Coast	(23.6)	$ (44.2)	$ (30.5)
Rocky Mountain	(0.8)	(5.3)	(1.9)
Permian	3.8	13.9	(0.2)
Mid-Continent [1]	—	(1.8)	0.5
Total	(20.6)	$ (37.4)	$ (32.1)

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

The 12 percent decrease in net equivalent production volumes offset by a slight increase in realized prices on a per BOE basis resulted in a 10 percent decrease in oil, gas, and NGL production revenues between the three months ended September 30, 2016, and 2015. This decrease in net equivalent production volumes, as well as the changes in costs on a per BOE basis discussed above, resulted in a 17 percent decrease in total production costs for the three months ended September 30, 2016, compared with the same period in 2015.

The following table presents the regional changes in our oil, gas, and NGL production, production revenues, and production costs between the nine months ended September 30, 2016, and 2015:

	Average Net Daily Production Increase (Decrease)	Production Revenues Decrease	Production Costs Decrease
	(MBOE/d)	(in millions)	(in millions)
South Texas & Gulf Coast	(20.8)	$ (256.5)	$ (79.8)
Rocky Mountain	(1.6)	(83.9)	(9.3)
Permian	0.8	(2.9)	(7.7)
Mid-Continent [(1)]	(6.1)	(25.8)	(11.9)
Total	(27.7)	$ (369.1)	$ (108.7)

(1) We divested our Mid-Continent assets in the second quarter of 2015.

The 15 percent decrease in net equivalent production volumes combined with an 18 percent decrease in realized prices on a per BOE basis, resulted in a 31 percent decrease in oil, gas, and NGL production revenues between the nine months ended September 30, 2016, and 2015. The decrease in net equivalent production volumes, as well as the changes in costs on a per BOE basis discussed above, resulted in a 20 percent decrease in total production costs for the nine months ended September 30, 2016, compared with the same period in 2015.

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 and discussion of trends on a per BOE basis. We expect our realized prices to trend with commodity prices.

Net gain on divestiture activity

The following table presents our net gain on divestiture activity for the periods presented:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Net gain on divestiture activity	$22.4	$2.4	$3.4	$38.5

The $22.4 million net gain on divestiture activity recorded for the three months ended September 30, 2016, is a result of closing divestitures in our Rocky Mountain and Permian regions during the third quarter of 2016. Certain of these sold assets were written down in the first quarter of 2016 and subsequently written up in the second quarter of 2016 based on changes in the estimated fair value less selling costs resulting in a small year-to-date gain.

The $38.5 million net gain recorded for the nine months ended September 30, 2015, resulted from the gain recorded on the sale of our Mid-Continent assets in the second quarter of 2015, partially offset by the write-down to fair value less costs to sell on certain assets held for sale in both the first and second quarters of 2015.

Please refer to Note 3 – Assets Held for Sale, Divestitures and Acquisitions in Part I, Item 1 of this report for additional discussion.

Other operating revenues

The following table presents our other operating revenues for the periods presented:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Other operating revenues	$1.1	$2.1	$2.0	$13.5

The decrease in other operating revenues for the three and nine months ended September 30, 2016, compared with the same periods in 2015, was driven by the sale of our Mid-Continent gas assets in the second quarter of 2015, which eliminated all marketed gas volumes and thus all marketed gas system revenues, which had been included in other operating revenues.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion

The following table presents our DD&A expense for the periods presented:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$194.0	$243.9	$619.2	$681.0

DD&A expense decreased 20 percent and nine percent for the three and nine months ended September 30, 2016, respectively, compared with the same periods in 2015. The decrease in our DD&A expense was a result of the decline in our production volumes and assets held for sale, partially offset by an increase in our DD&A rate in 2016. Please refer to the section A three-month and nine-month overview of selected production and financial information, including trends above for further 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,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Geological and geophysical expenses	$0.8	$0.9	$1.4	$5.6
Exploratory dry hole	—	—	—	22.9
Overhead and other expenses	12.7	18.8	40.5	54.1

Total	$13.5	$19.7	$41.9	$82.6

Exploration expense for the three and nine months ended September 30, 2016, decreased 31 percent and 49 percent, respectively, compared with the same periods in 2015. The decrease in our exploration expense for the three months ended September 30, 2016, as compared with the same period in 2015, was due to reduced overhead costs as a result of decreased headcount. The decrease in our exploration expense for the nine months ended September 30, 2016, as compared with the same period in 2015, was primarily due to exploratory dry holes being expensed in the first and second quarters of 2015, as well as reduced overhead costs as discussed above. 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. As a result of the current commodity price environment, we have reduced exploration activity and expect our exploratory dry hole, geological and geophysical, overhead and other exploration expenses to be lower in 2016 than in 2015.

Impairment of proved properties and abandonment and impairment of unproved properties

The following table presents our impairment of proved properties expense and abandonment and impairment of unproved properties expense for the periods presented:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Impairment of proved properties	$8.0	$56.0	$277.8	$124.4
Abandonment and impairment of unproved properties	$3.6	$6.6	$5.9	$24.0

The majority of our proved property impairment expense for the nine months ended September 30, 2016, was recorded in the first quarter of 2016 in our outside-operated Eagle Ford shale program as a result of continued commodity price declines. Additionally, we allowed certain leases to expire throughout the nine months ended September 30, 2016, and impaired unproved properties we no longer intended to develop.

Proved and unproved property impairments recorded for the three and nine months ended September 30, 2015, were due to commodity price declines, our decision to reduce capital invested in the development of certain prospects in our South Texas & Gulf Coast and Permian regions, and acreage we no longer intended to develop.

We expect proved property impairments to be more likely to occur in periods of declining commodity prices, and unproved property impairments to fluctuate with the timing of lease expirations, unsuccessful exploration activities, and changing economics associated with volatile commodity prices. Any amount of future impairment is difficult to predict, but based on updated commodity price assumptions as of October 26, 2016, we do not expect any material impairments in the fourth quarter of 2016 due to commodity price impacts. If commodity prices decline, downward revisions of proved reserves may be significant and could result in impairments in future periods. In addition to future commodity price declines, changes in drilling plans, downward engineering revisions, or unsuccessful exploration efforts may result in proved and unproved property impairments.

General and administrative

The following table presents our general and administrative expense, including the amount of exit and disposal costs captured in general and administrative expense, for the periods presented:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions)			
General and administrative	$32.7	$37.8	$93.1	$124.0
Exit and disposal costs [(1)]	$2.9	$1.0	$2.9	$9.5

[1] Exit and disposal costs are recorded in general and administrative expense in the accompanying statements of operations.

G&A expense decreased 14 percent and 25 percent for the three and nine months ended September 30, 2016, respectively, compared with the same periods in 2015, primarily due to lower headcount in 2016 than in 2015 and the impacts of recorded exit and disposal costs. Please refer to the section A three-month and nine-month overview of selected production and financial information, including trends above for further discussion of G&A expense on a per BOE basis.

Change in Net Profits Plan liability

The following table presents the change in our Net Profits Plan liability for the periods presented:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Change in Net Profits Plan liability	$(8.3)	$(4.4)	$(6.4)	$(13.2)

This non-cash expense (benefit) generally relates to the change between the reporting periods in the estimated value of the associated liability resulting from settlements made or accrued during the period and changes in assumptions used for production rates, reserve quantities, commodity pricing, discount rates, and production costs. The non-cash benefit for the three and nine months ended September 30, 2016, was primarily a result of cash payments accrued under the Net Profits Plan upon the divestiture of properties subject to the Net Profits Plan in our Rocky Mountain and Permian regions during the third quarter of 2016. Similarly, the non-cash benefit for the nine months ended September 30, 2015, resulted from cash payments made under the Net Profits Plan related to the divestiture of certain Mid-Continent assets subject to the Net Profits Plan, in addition to the decline in commodity prices throughout 2015. As of September 30, 2016, our Net Profits Plan liability was $1.2 million, therefore, future changes resulting from fluctuations in commodity prices or additional divestitures are not expected to be significant.

Derivative (gain) loss

The following table presents our derivative (gain) loss for the periods presented:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Derivative (gain) loss	$(28.0)	$(212.3)	$121.1	$(285.5)

We recognized a derivative gain for the three months ended September 30, 2016, and a derivative loss for the nine months ended September 30, 2016. Contracts settled during the three months ended September 30, 2016, had a fair value of $41.6 million at June 30, 2016, and settled for $57.5 million, which resulted in a $15.9 million gain. Additionally, we recorded a $12.1 million increase during the three months ended September 30, 2016, in the fair value of contracts settling subsequent to September 30, 2016. Contracts settled during the nine months ended September 30, 2016, had a fair value of $310.3 million at December 31, 2015, and settled at a $4.1 million loss. Additionally, we recorded a $117.0 million mark-to-market loss on remaining contracts as of September 30, 2016, which includes trades entered into during 2016, resulting from the increase in commodity strip prices.

We recognized a derivative gain for both the three and nine months ended September 30, 2015. Contracts settled during the three months ended September 30, 2015, had a fair value of $79.0 million at June 30, 2015, and settled for $113.7 million, resulting in a $34.7 million gain. Additionally, we recorded a $177.6 million increase during the three months ended September 30, 2015, in the fair value of contracts settling subsequent to September 30, 2015. Contracts settled during the nine months ended September 30, 2015, had a fair value of $328.7 million at December 31, 2014, and settled at a $59.0 million gain. Included in these settlements was a $15.3 million gain on the early settlement of future contracts resulting from the divestiture of our Mid-Continent assets during the second quarter of 2015. Additionally, a $226.5 million mark-to-market gain was recorded on remaining contracts as of September 30, 2015.

Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report for additional information.

Other operating expenses

The following table presents our other operating expenses for the periods presented:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Other operating expenses	$2.4	$7.2	$14.2	$34.6

Other operating expenses for the three and nine months ended September 30, 2016, consist primarily of drilling rig termination and standby fees of $1.1 million and $8.7 million, respectively, with the remaining expense being related to legal settlements and equipment inventory write-downs. This compares to drilling rig termination and standby fees of $2.2 million and $8.1 million recorded for the three and nine months ended September 30, 2015, respectively. The decrease in other operating expenses for the nine months ended September 30, 2016, as compared with the same period in 2015, was primarily due to the sale of our Mid-Continent gas assets in the second quarter of 2015, which eliminated all marketed gas volumes and all marketed gas system expenses, which had been included in other operating expenses. Additionally, we recorded a $4.6 million contingent accrual during the nine months ended September 30, 2015, related to estimated claims of payment of royalties on certain Federal and Indian leases, which was reduced during the nine months ended September 30, 2016. Please refer to Note 6 - Commitments and Contingencies in Part I, Item I of this report for additional information.

Gain (loss) on extinguishment of debt

The following table presents our gain (loss) on extinguishment of debt for the periods presented:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Gain (loss) on extinguishment of debt	$—	$—	$15.7	$(16.6)

During the first quarter of 2016, we recorded a $15.7 million net gain on the early extinguishment of a portion of our 6.50% Senior Notes due 2021, 6.125% Senior Notes due 2022, and 6.50% Senior Notes due 2023, which includes approximately $16.4 million associated with the discount realized upon repurchase, slightly offset by approximately $700,000 related to 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.

During the second quarter of 2015, we recorded a $16.6 million loss on the early extinguishment of our 6.625% Senior Notes due 2019, 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.

Interest expense

The following table presents our interest expense for the periods presented:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Interest expense	$(47.2)	$(33.2)	$(112.3)	$(96.6)

The increase in interest expense for the three and nine months ended September 30, 2016, compared with the same periods in 2015, was partially due to a slight increase in our weighted-average interest rate, as presented in Overview of Liquidity and Capital Resources under caption Weighted-Average Interest Rates below. Additionally, during the third quarter of 2016, we paid $10.0 million to terminate a second lien facility that was no longer necessary to fund the Rock Oil Acquisition due to the equity offering and Senior Convertible Notes issuance.

Income tax benefit

The following table presents our income tax benefit and effective tax rate for the periods presented:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions, except tax rate)			
Income tax benefit	$23.7	$4.1	$314.5	$78.3
Effective tax rate	36.7 %	403.5 %	36.1 %	42.2 %

The decrease in the effective tax rate for the three and nine months ended September 30, 2016, compared with the same periods in 2015, resulted from 2015 discrete benefits realized from finalization of the R&D credit claim in the first quarter of 2015, enacted state rate changes in the second quarter of 2015, and a state capital gain deduction recognized in the third quarter of 2015. Please refer to Note 4 - Income Taxes in Part I, Item 1 of this report for additional discussion.

Overview of Liquidity and Capital Resources

Based on the current commodity price environment, 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 2016 capital program, excluding acquisitions, to be funded by cash flows from operations, with any remaining cash needs to be funded by borrowings under our credit facility and proceeds received from the divestiture of properties. The proceeds from our equity, Senior Convertible Notes, and 2026 Notes offerings during the third quarter of 2016 were sufficient to fund the Rock Oil Acquisition, which closed subsequent to September 30, 2016. We plan to fund the QStar Acquisition expected to close mid-December 2016 with proceeds from the expected divestiture of our Raven/Bear Den assets, borrowings under our credit facility, and a private issuance of shares of our common stock to the sellers. See Credit Facility below for a discussion of our most recent borrowing base redetermination.

Although we anticipate cash flows from these sources will be sufficient to fund our expected 2016 capital program, we may also elect to raise funds through debt financing or from other sources or enter into carrying cost funding and sharing arrangements with third parties for particular exploration and/or development programs. Decreases in commodity prices have limited our industry’s access to capital markets in recent periods. If we raise additional funds through the issuance of equity or convertible debt securities, the percentage ownership of our stockholders could be significantly diluted, and these newly-issued securities may have rights, preferences, or privileges senior to those of existing stockholders. During the first quarter of 2016, our credit ratings were downgraded by two major rating agencies. These downgrades and any future downgrades may make it more difficult or expensive for us to borrow additional funds. 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. Our credit facility borrowing base could be further reduced as a result of lower commodity prices, divestitures of proved properties, or newly issued debt.

We have no control over the market prices for oil, gas, or NGLs, although we may be 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. During the nine months ended September 30, 2016, cash received from the settlement of commodity derivative contracts provided a significant positive source of cash, which is reflected in net cash provided by operating activities in our accompanying condensed consolidated statements of cash flows. The fair value of our commodity derivative contracts was a net asset of $61.1 million at September 30, 2016, of which $24.6 million relates to contracts expected to settle in the fourth quarter of 2016. The remaining asset position relates to contracts expected to settle in 2017, as our contracts beyond December 31, 2017, are in a liability position based on September 30, 2016, forward pricing. As our derivative contracts settle in future periods, and if commodity prices remain at current levels or decline further, our future cash flows from operations will be negatively 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.

Proposals to reform the Internal Revenue Code of 1986, as amended, 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 that 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 Agreement provides for a maximum loan amount of $2.5 billion and a maturity date of December 10, 2019. As of September 30, 2016, our borrowing base and the current aggregate lender commitments were $1.1 billion. The reduction during the third quarter of 2016 was a result of the issuance of the Senior Convertible Notes and 2026 Notes. On September 30, 2016, we entered into an Eighth Amendment to the Credit Agreement. Pursuant to the amendment, and as part of the regular, semi-annual borrowing base redetermination process, the borrowing base was increased to $1.35 billion and current aggregate lender commitments were increased to $1.25 billion. This increase was primarily due to the value attributed to the properties acquired in the Rock Oil Acquisition and increasing commodity prices, and was not effective until the closing of the acquisition on October 4, 2016. No individual bank that is a party to our Credit Agreement represents more than 10 percent of the lender commitments. 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 outstanding, and available borrowing capacity under our credit facility as of October 26, 2016, September 30, 2016, and December 31, 2015.

We must comply with certain financial and non-financial covenants under the terms of the Credit Agreement, including covenants limiting dividend payments and requiring us to maintain certain financial ratios, as defined by the Credit Agreement. As of September 30, 2016, financial covenants under the Credit Agreement require, as of the last day of each of our fiscal quarters, our (a) ratio of senior secured debt to 12-month trailing adjusted EBITDAX to be not more than 2.75 to 1.0; (b) adjusted current ratio to be not less than 1.0 to 1.0; and (c) ratio of 12-month trailing adjusted EBITDAX to interest expense to be not less than 2.0 to 1.0. We were in compliance with all financial and non-financial covenants under the Credit Agreement as of September 30, 2016, and through the filing date of this report. Please refer to the caption Non-GAAP Financial Measures below for the calculation of adjusted EBITDAX, and a reconciliation of adjusted EBITDAX to net income (loss) and to net cash provided by operating activities.

Our daily weighted-average credit facility debt balance was approximately $156.0 million and $239.7 million for the three and nine months ended September 30, 2016, respectively. 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. Cash flows provided by our operating activities, proceeds received from divestitures of properties, capital markets activities, and the amount of our capital expenditures, including acquisitions, all impact the amount we have borrowed under our credit facility.

Weighted-Average Interest Rates

Our 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 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, 2016, and 2015:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
Weighted-average interest rate	6.2%	6.0%	6.1%	6.0%
Weighted-average borrowing rate	5.7%	5.6%	5.6%	5.5%

Our weighted-average interest rates and weighted-average borrowing rates in 2016 and 2015 have been impacted by the timing of Senior Notes and Senior Convertible Notes issuances and redemptions, 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 do not reflect the approximate $16.4 million associated with the discount realized upon repurchase of certain of our Senior Notes during the first quarter of 2016, the approximate $700,000 related to the acceleration of unamortized deferred financing costs expensed upon repurchase, or the $10.0 million fee paid to terminate an unused second lien facility in the third quarter of 2016. Please refer to Note 5 - Long-Term Debt in Part I, Item 1 of this report for additional discussion. The rates disclosed in the above table for the three and 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.

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 acquisition, exploration, and development of oil and gas properties are the primary use of our capital resources. For the nine months ended September 30, 2016, we spent $514.6 million 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, and exploration overhead amounts.

As of September 30, 2016, we had a $980.7 million cash balance on the accompanying balance sheet, which we used to fund the Rock Oil Acquisition that closed on October 4, 2016. Upon executing the purchase agreement in August 2016, we paid a $49.0 million deposit, which was reflected as restricted cash on the accompanying balance sheet and applied to the adjusted purchase price of $991.0 million upon closing.

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 outside-operated exploration and development 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 including covenants in our Credit Agreement, compliance with securities laws, and other factors. The amounts involved in any such transaction may be material. During the nine months ended September 30, 2016, we repurchased a portion of our 6.50% Senior Notes due 2021, 6.125% Senior Notes due 2022, and 6.50% Senior Notes due 2023, in open market transactions, at a discount, resulting in a $15.7 million net gain on extinguishment of debt. 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 Agreement, the indentures governing our Senior Notes, the indenture governing our Senior Convertible 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 2016.

Analysis of Cash Flow Changes Between the Nine Months Ended September 30, 2016, and 2015

The following tables present changes in cash flows between the nine months ended September 30, 2016, and 2015, for our operating, investing, and financing activities. The analysis following each table should be read in conjunction with our condensed consolidated statements of cash flows in Part I, Item 1 of this report.

Operating Activities

	For the Nine Months Ended September 30,		Amount Change Between Periods	Percent Change Between Periods
	2016	2015		
	(in millions)			
Net cash provided by operating activities	$415.0	$784.8	$(369.8)	(47)%

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Cash received from oil, gas, and NGL production revenues, net of transportation costs and production taxes, including derivative cash settlements, decreased $510.3 million for the nine months ended September 30, 2016, compared with the same period in 2015, as a result of the decline in both production volumes and realized commodity prices. Cash paid for LOE, excluding ad valorem tax expense, decreased $46.0 million for the nine months ended September 30, 2016, compared with the same period in 2015, due to a decrease in production volumes and lower service provider costs. During the third quarter of 2016, we paid $10.0 million to terminate a second lien facility that was not needed to fund the Rock Oil Acquisition. During the nine months ended September 30, 2015, we paid $12.5 million associated with the premium for the tender offer and redemption of the 6.625% Senior Notes due 2019. The remaining reduction is related to decreases in cash G&A expense and exploration overhead, as well as changes in working capital balances.

Investing activities

	For the Nine Months Ended September 30,		Amount Change Between Periods	Percent Change Between Periods
	2016	2015		
	(in millions)			
Net cash used in investing activities	$(361.8)	$(934.8)	$ 573.0	61 %

Net cash used in investing activities decreased for the nine months ended September 30, 2016, compared with the same period in 2015. Capital expenditures for the nine months ended September 30, 2016, decreased $769.1 million, or 61 percent, compared with the same period in 2015. Drilling, completion, and facilities capital expenditures decreased approximately 54 percent for the nine months ended September 30, 2016, as compared with the same period in 2015, as a result of a reduced operated rig count and lower service provider costs. Additionally, we paid a significant amount of year-end 2014 accrued payables during the first half of 2015. We acquired $21.9 million of primarily unproved properties in the Midland Basin during the nine months ended September 30, 2016, compared with $7.1 million of proved and unproved property acquisitions in our Gooseneck prospect area in the same period in 2015. Additionally, we made a $49.0 million deposit on the Rock Oil Acquisition during the third quarter of 2016. Net proceeds from the sale of oil and gas properties decreased $133.3 million for the nine months ended September 30, 2016, compared with the same period in 2015, primarily due to the divestiture of our Mid-Continent assets during the second quarter of 2015.

Financing activities

	For the Nine Months Ended September 30,		Amount Change Between Periods	Percent Change Between Periods
	2016	2015		
	(in millions)			
Net cash provided by financing activities	$927.5	$150.1	$ 777.4	518 %

For the nine months ended September 30, 2016, we received $530.9 million net proceeds from our underwritten public equity offering, $166.7 million net proceeds from our Senior Convertible Notes issuance, and $492.4 million net proceeds from our 2026 Notes issuance. Additionally, we paid $24.1 million for capped call transactions related to our Senior Convertible Notes issuance. We used the net cash proceeds from these transactions to pay down our credit facility balance as of September 30, 2016, resulting in net repayments of $202.0 million for the nine months ended September 30, 2016. The remaining proceeds were used to fund the Rock Oil Acquisition that closed October 4, 2016. During the nine months ended September 30, 2016, we paid $29.9 million for the repurchase of $46.3 million in aggregate principal amount of our 6.50% Senior Notes due 2021, 6.125% Senior Notes due 2022, and 6.50% Senior Notes due 2023. In the second quarter of 2015, we received $491.0 million of net proceeds from the issuance of our 2025 Notes. These proceeds were primarily used for the tender and redemption of the principal amount of $350.0 million of our 2019 Notes. We had net borrowings of $18.0 million under our credit facility during the nine months ended September 30, 2015. Please refer to Note 5 - Long-Term Debt in Part I, Item 1 of this report for additional discussion.

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 or fixed-rate Senior Convertible Notes, but can impact their fair market values. As of September 30, 2016, our fixed-rate debt outstanding totaled $3.0 billion. As of September 30, 2016, we had no floating-rate debt outstanding, thus we had no exposure to market risk related to floating interest rates at that date. 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 and Senior Convertible 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 over the last couple of years, 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 and we cannot reasonably predict future commodity prices. Based on our production for the nine months ended September 30, 2016, 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 $43.6 million, $23.7 million, and $15.9 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, 2016, a 10 percent decrease in the contract settlement prices, would have increased our oil, gas, and NGL derivative settlement gain by approximately $24.0 million, $15.8 million, and $10.4 million, respectively.

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 we determine 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 2016.

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 2015 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, depletion, depreciation, amortization, and accretion expense, exploration expense, impairments, non-cash stock-based compensation expense, derivative gains and losses net of settlements, change in the Net Profits Plan liability, gains and losses on divestitures, and gains or losses on extinguishment of debt. 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 we present because we believe 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 financial covenants under our Credit Agreement based on adjusted EBITDAX ratios as further described in Note 5 - Long-Term Debt in Part I, Item 1 of this report. 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. Our credit facility provides a material source of liquidity for us. Under the terms of our Credit Agreement, if we fail to comply with the covenants that establish a maximum permitted ratio of senior secured debt to adjusted EBITDAX and a minimum permitted ratio of interest to adjusted EBITDAX, we will be in default, an event that would prevent us from borrowing under our credit facility and would therefore materially limit our sources of liquidity. In addition, if we default under our credit facility and are unable to obtain a waiver of that default from our lenders, lenders under that facility and under the indentures governing our outstanding Senior Notes and Senior Convertible Notes would be entitled to exercise all of their remedies for a default.

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,	
	2016	2015	2016	2015
	(in thousands)			
Net income (loss) (GAAP)	$(40,907)	$3,114	$(556,798)	$(107,452)
Interest expense	47,206	33,157	112,329	96,583
Other non-operating income, net	(221)	(27)	(232)	(623)
Income tax benefit	(23,732)	(4,140)	(314,505)	(78,296)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	193,966	243,879	619,193	680,984
Exploration (1)	11,892	17,798	36,905	77,298
Impairment of proved properties	8,049	55,990	277,834	124,430
Abandonment and impairment of unproved properties	3,568	6,600	5,917	24,046
Stock-based compensation expense	6,570	7,277	20,485	20,492
Derivative (gain) loss	(28,037)	(212,253)	121,086	(285,491)
Derivative settlement gain (2)	57,496	113,695	306,234	387,719
Change in Net Profits Plan liability	(8,314)	(4,364)	(6,449)	(13,174)
Net gain on divestiture activity	(22,388)	(2,415)	(3,413)	(38,497)
(Gain) loss on extinguishment of debt	—	—	(15,722)	16,578
Materials inventory impairment	—	1,045	1,692	3,901
Adjusted EBITDAX (Non-GAAP)	205,148	259,356	604,556	908,498
Interest expense	(47,206)	(33,157)	(112,329)	(96,583)
Other non-operating income, net	221	27	232	623
Income tax benefit	23,732	4,140	314,505	78,296
Exploration (1)	(11,892)	(17,798)	(36,905)	(77,298)
Exploratory dry hole expense	8	(36)	(16)	22,860
Amortization of discount and deferred financing costs	3,757	1,911	5,687	5,803
Deferred income taxes	(23,756)	4,168	(314,770)	(80,388)
Plugging and abandonment	(2,506)	(2,154)	(5,222)	(5,540)
Loss on extinguishment of debt	—	—	—	(12,455)
Other, net	(3,068)	3,059	(4,084)	(231)
Changes in current assets and liabilities	13,701	15,825	(36,642)	41,264
Net cash provided by operating activities (GAAP)	$158,139	$235,341	$415,012	$784,849

(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) Natural gas derivative settlements for the nine months ended September 30, 2015, include a $15.3 million gain on the early settlement of future 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 of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended (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,” “fore “intend,” “plan,” “project,” “will,” and similar expressions are intended to identify forward-looking statements. Forward-looking statements appear throughout 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;
- our outlook on future oil, gas, and NGL prices, well costs, and service costs;
- the drilling of wells and other exploration and development activities and plans, as well as possible or expected acquisitions or divestitures;
- 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;
- 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 in the Risk Factors section in Part I, Item 1A of our 2015 Form 10-K, and include such factors as:

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

- the possibility that exploration and development drilling may not result in commercially producible reserves;
- our limited control over activities on outside-operated properties;
- our reliance on the skill and expertise of third-party service providers on our operated properties;
- the possibility that title to properties in which we claim 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; 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 2015 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 our 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

There were no changes during the third quarter of 2016 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

There have been no material changes to the legal proceedings as previously disclosed in our 2015 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

Other than the risk factors described below, there have been no material changes to the risk factors as previously disclosed in our 2015 Form 10-K.

Acquisitions or divestitures may not be completed as anticipated, or if completed, may not be beneficial to us.

We have executed agreements for (and in some cases already closed) the acquisition of assets in the Midland Basin and for the divestiture of certain Rocky Mountain assets, including our Raven/Bear Den assets. There are a number of risks and uncertainties relating to the acquisition and divesiture of oil and natural gas assets. For example, acquisitions or divestitures may not be completed at all, or may not be completed in the time frame, on the terms, or in the manner anticipated, as a result of a number of factors, including any required closing conditions.

The consummation of an acquisition or divestiture may involve many potential risks, including:

- the assumption or retention of material liabilities;
- the assimilation, retention or termination of employees;
- the failure to realize recoverable reserves;
- the failure to realize an expected purchase price for a divestiture as a result of purchase price adjustments, indemnification obligations or otherwise;
- regulatory approvals, compliance and permitting;
- title issues or other unidentified or unforeseeable liabilities and costs;
- the incurrence of liabilities or other compliance costs related to environmental or regulatory matters, including potential liabilities that may be imposed without regard to fault or the legality of conduct;
- the diversion of management's attention from our existing properties or business;
- additional costs or expenses or a significant increase in our interest expense and financial leverage resulting from any additional debt incurred to finance an acquisition; and
- the incurrence of significant charges, such as asset devaluation or restructuring charges.

If we consummate the pending acquisition and expected divestiture or another acquisition or divestiture of assets and if these risks or other unanticipated risks were to materialize, any expected benefits of an acquisition or divestiture may not be fully realized, if at all, and our future financial performance and results of operations could be negatively impacted. We cannot assure you that we will realize value from any acquisition that equals or exceeds the consideration paid and obligations assumed.

If completed, an acquisition or divestiture of oil and natural gas assets may not achieve its expected results and may result in us assuming or retaining unanticipated liabilities. An acquisition or divestiture may involve a material amount of acreage relative to our prior acreage position and a material purchase price relative to our prior strategic activities. We entered into our recently closed and pending acquisitions and divestitures expecting to receive various benefits, growth opportunities, and synergies. Achieving the anticipated benefits of any acquisition or divestiture is subject to a number of risks and uncertainties. For example, in an acquisition, we often have the opportunity to conduct customary environmental and title due diligence once we execute a definitive purchase agreement. As a result, we may discover title defects or adverse environmental or other conditions or liabilities of which we are currently unaware. Environmental, title and other conditions or liabilities could reduce the value of the properties that we acquire or divest of, and, depending on the circumstances, we could have limited or no recourse with respect to those problems. In acquisitions or divestitures, we often assume or retain certain liabilities and may be entitled or obligated to indemnification in connection with those liabilities in only limited circumstances and in limited amounts. We cannot assure that such potential remedies will be adequate for any liabilities we incur, and such liabilities could be significant.

The risks involved in an acquisition or divestiture may be heightened due to the size of the acquisition or divestiture if it is a material amount of acreage relative to our prior acreage position and a material purchase price relative to our prior strategic activities.

The expected future growth of our business will impose significant added responsibilities on management, and may place strain on our administrative and operational infrastructures. Our senior management's attention may be diverted from the management of daily operations to the integration or winding down of operations and assets in an acquisition or divestiture. Our ability to manage our business and growth will require us to apply our operational, financial and management controls, reporting systems and procedures to the acquired business. We may also encounter risks, costs and expenses associated with any undisclosed or other unanticipated liabilities, and use more cash and other financial resources on integration and implementation activities than we anticipate. After an acquisition, we may not be able to successfully integrate operations into our existing operations, successfully manage additional acreage, or realize the expected economic benefits, which may have a material adverse effect on our business, financial condition, and results of operations, including any cash available for distribution to our stockholders.

Actual reserves and production associated with the properties to be acquired in an acquisition may be substantially less than we expect.

With any acquisition, its success depends on, among other things, the accuracy of our assessment of the number and quality of the drilling locations associated with the properties acquired, future oil and natural gas prices, reserves and production, and future operating costs and various other factors. These assessments are necessarily inexact. Our future assessment of certain of these factors is often based in part on information provided to us by the seller, including historical production data. Our independent reserve engineers often do not provide either a report regarding the estimates of reserves nor an audit of the reserves with respect to the properties subject to an acquisition. The assumptions on which our internal estimates have been based may prove to be incorrect in a number of material ways, resulting in our not realizing the expected benefits of an acquisition. In addition, the representations, warranties, and indemnities of the seller contained in a purchase agreement may be limited, and we may not have recourse against the seller in the event that the acreage is less valuable than we believe. As a result, we may not recover the purchase price for an acquisition from the properties being acquired or recognize an acceptable return from such sales.

The development of any properties that are acquired are subject to all of the risks and uncertainties associated with oil and natural gas activities as described in the "Risk Factors" section of our 2015 Form 10-K.

If a significant portion of the value of an acquisition is associated with undeveloped acreage, it may not be economic.

A large portion of the acreage we acquired in the Rock Oil Acquisition and expect to acquire in the QStar Acquisition is undeveloped, and our plans, development schedule, and production schedule associated with the acreage may fail to materialize. As a result, our investment in this acreage may not be as economic as we expect, and we could incur material write-downs of unevaluated properties.

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

(c) The following table provides information about purchases by our company or any "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Exchange Act) during the quarter ended September 30, 2016, of shares of our common stock, which is the sole class of equity securities registered by our company pursuant to Section 12 of the Exchange Act:

PURCHASES OF EQUITY SECURITIES BY ISSUER
AND AFFILIATED PURCHASERS

	(a)	(b)	(c)	(d)
Period	Total Number of Shares Purchased (1)	Weighted Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Maximum Number of Shares that May Yet Be Purchased Under the Program (2)
07/01/16 - 07/31/16	84,856	$ 27.00	—	3,072,184
08/01/16 - 08/31/16	562	$ 29.62	—	3,072,184
09/01/16 - 09/30/16	—	$ —	—	3,072,184
Total:	85,418	$ 27.02	—	3,072,184

(1) All shares purchased by our company in the third quarter of 2016 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 Agreement, the indentures governing our Senior Notes, the indentures governing our Senior Convertible 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 Agreement 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 and the indentures governing our Senior Convertible 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 Number	Description
1.1	Underwriting Agreement dated August 8, 2016 by and among SM Energy Company and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and J.P. Morgan Securities LLC, as representatives of the several underwriters named therein (filed as Exhibit 1.1 to the registrant’s Current Report on Form 8-K filed on August 12, 2016, and incorporated herein by reference)
1.2	Underwriting Agreement dated August 8, 2016 by and among SM Energy Company and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and J.P. Morgan Securities LLC, as representatives of the several underwriters named therein (filed as Exhibit 1.2 to the registrant’s Current Report on Form 8-K filed on August 12, 2016, and incorporated herein by reference)
1.3	Underwriting Agreement dated September 7, 2016 by and among SM Energy Company and Merrill Lynch, Pierce, Fenner & Smith Incorporated, Wells Fargo Securities, LLC, and J.P. Morgan Securities LLC, as representatives of the several underwriters named therein (filed as Exhibit 1.1 to the registrant’s Current Report on Form 8-K filed on September 12, 2016, and incorporated herein by reference)
2.1	Membership Interest Purchase Agreement dated August 8, 2016 between SM Energy Company and Rock Oil Holdings LLC (filed as Exhibit 2.1 to the registrant’s Current Report on Form 8-K filed on August 8, 2016, and incorporated herein by reference)
2.2	Purchase and Sale Agreement, dated as of October 17, 2016, by and between SM Energy Company and QStar LLC (filed as Exhibit 2.1 to the registrant’s Current Report on Form 8-K filed on October 21, 2016, and incorporated herein by reference)
2.3	Letter Agreement dated as of October 17, 2016, by and among SM Energy Company, QStar LLC, and RRP-QStar, LLC (filed as Exhibit 2.2 to the registrant’s Current Report on Form 8-K filed on October 21, 2016, and incorporated herein by reference)
2.4	Purchase and Sale Agreement dated as of October 17, 2016, by and between SM Energy Company and Oasis Petroleum North America LLC (filed as Exhibit 2.3 to the registrant’s Current Report on Form 8-K filed on October 21, 2016, and incorporated herein by reference)
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 15, 2015 (filed as Exhibit 3.1 to the registrant’s Current Report on Form 8-K filed on December 21, 2015, and incorporated herein by reference)
4.1	Base Indenture, dated as of May 21, 2015, by and between SM Energy Company and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the registrant’s Current Report on Form 8-K filed on August 12, 2016, and incorporated herein by reference)
4.2	Second Supplemental Indenture, dated as of August 12, 2016, by and between SM Energy Company and US Bank, National Association, as trustee (filed as Exhibit 4.2 to the registrant’s Current Report on Form 8-K filed on August 12, 2016, and incorporated herein by reference)
4.3	Third Supplemental Indenture, dated as of September 12, 2016 by and between SM Energy Company and US Bank National Association, as trustee (filed as Exhibit 4.2 to the registrant’s Current Report on Form 8-K filed on September 12, 2016, and incorporated herein by reference)
10.1	Seventh Amendment to Fifth Amended and Restated Credit Agreement, dated August 8, 2016, 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 August 9, 2016, and incorporated herein by reference)
10.2	

	Eighth Amendment to Fifth Amended and Restated Credit Agreement, dated September 30, 2016, 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 6, 2016 and incorporated herein by reference)
10.3	Call Option Confirmation, dated August 8, 2016, by and between SM Energy Company and Wells Fargo Bank, National Association (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on August 12, 2016, and incorporated herein by reference)
10.4	Call Option Confirmation, dated August 8, 2016, by and between SM Energy Company and Bank of America, N.A. (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on August 12, 2016, and incorporated herein by reference)

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10.5	Call Option Confirmation, dated August 8, 2016, by and between SM Energy Company and JPMorgan Chase Bank, National Association (filed as Exhibit 10.3 to the registrant's Current Report on Form 8-K filed on August 12, 2016, and incorporated herein by reference)
10.6	Call Option Confirmation, dated August 10, 2016, by and between SM Energy Company and Wells Fargo Bank, National Association (filed as Exhibit 10.4 to the registrant's Current Report on Form 8-K filed on August 12, 2016, and incorporated herein by reference)
10.7	Call Option Confirmation, dated August 10, 2016, by and between SM Energy Company and Bank of America, N.A. (filed as Exhibit 10.5 to the registrant's Current Report on Form 8-K filed on August 12, 2016, and incorporated herein by reference)
10.8	Call Option Confirmation, dated August 10, 2016, by and between SM Energy Company and JPMorgan Chase Bank, National Association (filed as Exhibit 10.6 to the registrant's Current Report on Form 8-K filed on August 12, 2016, 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.
† Exhibit constitutes a management contract or compensatory plan or agreement.

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

November 2, 2016
By: /s/ JAVAN D. OTTOSON
Javan D. Ottoson
President and Chief Executive Officer
(Principal Executive Officer)

November 2, 2016
By: /s/ A. WADE PURSELL
A. Wade Pursell
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

November 2, 2016
By: /s/ MARK T. SOLOMON
Mark T. Solomon
Vice President - Controller and Assistant Secretary
(Principal Accounting Officer)