SM Energy Co
Form 10-Q
November 03, 2017

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

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

For the quarterly period ended September 30, 2017

OR

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

For the transition period from ___________ to ___________

Commission File Number 001-31539

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, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth 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
	Emerging growth company o

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. 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, 2017, the registrant had 111,624,029 shares of common stock, $0.01 par value, outstanding.

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

	September 30, 2017	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 441,415	$ 9,372
Accounts receivable	146,056	151,950
Derivative asset	63,685	54,521
Prepaid expenses and other	17,756	8,799
Total current assets	668,912	224,642
Property and equipment (successful efforts method):		
Proved oil and gas properties	5,938,351	5,700,418
Less - accumulated depletion, depreciation, and amortization	(3,243,072)	(2,836,532)
Unproved oil and gas properties	2,321,508	2,471,947
Wells in progress	287,106	235,147
Oil and gas properties held for sale, net	7,144	372,621
Other property and equipment, net of accumulated depreciation of $50,468 and $42,882, respectively	106,046	137,753
Total property and equipment, net	5,417,083	6,081,354
Noncurrent assets:		
Derivative asset	60,035	67,575
Other noncurrent assets	32,896	19,940
Total other noncurrent assets	92,931	87,515
Total Assets	$ 6,178,926	$ 6,393,511
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 348,885	$ 299,708
Derivative liability	87,791	115,464
Total current liabilities	436,676	415,172
Noncurrent liabilities:		
Revolving credit facility	—	—
Senior Notes, net of unamortized deferred financing costs	2,768,346	2,766,719
Senior Convertible Notes, net of unamortized discount and deferred financing costs	137,012	130,856
Asset retirement obligation	100,958	96,134
Asset retirement obligation associated with oil and gas properties held for sale	—	26,241
Deferred income taxes	208,720	315,672
Derivative liability	67,676	98,340
Other noncurrent liabilities	47,497	47,244
Total noncurrent liabilities	3,330,209	3,481,206
Commitments and contingencies (note 6)		

Stockholders’ equity:		
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued and outstanding: 111,624,029 and 111,257,500 shares, respectively	1,116	1,113
Additional paid-in capital	1,734,217	1,716,556
Retained earnings	691,915	794,020
Accumulated other comprehensive loss	(15,207)	(14,556)
Total stockholders’ equity	2,412,041	2,497,133
Total Liabilities and Stockholders’ Equity	$ 6,178,926	$ 6,393,511

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,	
	2017	2016	2017	2016
Operating revenues and other income:				
Oil, gas, and NGL production revenue	$294,459	$329,165	$912,596	$832,130
Net gain (loss) on divestiture activity	(1,895)	22,388	(131,565)	3,413
Other operating revenues	2,815	1,107	7,807	2,007
Total operating revenues and other income	295,379	352,660	788,838	837,550
Operating expenses:				
Oil, gas, and NGL production expense	122,651	152,524	385,073	445,658
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	134,599	193,966	425,643	619,193
Exploration	14,243	13,482	39,293	41,942
Impairment of proved properties	—	8,049	3,806	277,834
Abandonment and impairment of unproved properties	—	3,568	157	5,917
General and administrative	27,880	32,679	85,564	93,117
Net derivative (gain) loss	80,599	(28,037)	(89,364)	121,086
Other operating expenses, net	999	(5,917)	6,303	7,731
Total operating expenses	380,971	370,314	856,475	1,612,478
Loss from operations	(85,592)	(17,654)	(67,637)	(774,928)
Non-operating income (expense):				
Interest expense	(44,091)	(47,206)	(135,639)	(112,329)
Gain (loss) on extinguishment of debt	—	—	(35)	15,722
Other, net	1,301	221	2,901	232
Loss before income taxes	(128,382)	(64,639)	(200,410)	(871,303)
Income tax benefit	39,270	23,732	65,825	314,505
Net loss	$(89,112)	$(40,907)	$(134,585)	$(556,798)
Basic weighted-average common shares outstanding	111,575	78,468	111,366	71,574
Diluted weighted-average common shares outstanding	111,575	78,468	111,366	71,574
Basic net loss per common share	$(0.80)	$(0.52)	$(1.21)	$(7.78)
Diluted net loss per common share	$(0.80)	$(0.52)	$(1.21)	$(7.78)
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.

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,	
	2017	2016	2017	2016
Net loss	$(89,112)	$(40,907)	$(134,585)	$(556,798)
Other comprehensive loss, net of tax:				
Pension liability adjustment	(208)	(255)	(651)	(760)
Total other comprehensive loss, net of tax	(208)	(255)	(651)	(760)
Total comprehensive loss	$(89,320)	$(41,162)	$(135,236)	$(557,558)

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	Retained	Accumulated Other Comprehensive	Total Stockholders'
	Shares	Amount	Capital	Earnings	Loss	Equity
Balances, December 31, 2016	111,257,500	$1,113	$1,716,556	$794,020	$(14,556)	$2,497,133
Net loss	—	—	—	(134,585)	—	(134,585)
Other comprehensive loss	—	—	—	—	(651)	(651)
Dividends, $0.10 per share	—	—	—	(11,144)	—	(11,144)
Issuance of common stock under Employee Stock Purchase Plan	123,678	1	1,737	—	—	1,738
Issuance of common stock upon vesting of restricted stock units, net of shares used for tax withholdings	171,278	1	(1,241)	—	—	(1,240)
Stock-based compensation expense	71,573	1	16,159	—	—	16,160
Cumulative effect of accounting change (1)	—	—	1,108	43,624	—	44,732
Other	—	—	(102)	—	—	(102)
Balances, September 30, 2017	111,624,029	$1,116	$1,734,217	$691,915	$(15,207)	$2,412,041

(1) Refer to Note 2 - Basis of Presentation, Significant Accounting Policies, and Recently Issued Accounting Standards.

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

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

	For the Nine Months Ended September 30,	
	2017	2016
Cash flows from operating activities:		
Net loss	$(134,585)	$(556,798)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Net (gain) loss on divestiture activity	131,565	(3,413)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	425,643	619,193
Impairment of proved properties	3,806	277,834
Abandonment and impairment of unproved properties	157	5,917
Stock-based compensation expense	16,160	20,485
Net derivative (gain) loss	(89,364)	121,086
Derivative settlement gain	29,402	306,234
Amortization of debt discount and deferred financing costs	12,478	5,687
Non-cash (gain) loss on extinguishment of debt, net	22	(15,722)
Deferred income taxes	(67,458)	(314,770)
Plugging and abandonment	(2,095)	(5,222)
Other, net	4,713	(8,857)
Changes in current assets and liabilities:		
Accounts receivable	21,502	1,221
Prepaid expenses and other	(8,955)	7,652
Accounts payable and accrued expenses	21,560	(65,166)
Accrued derivative settlements	6,046	19,651
Net cash provided by operating activities	370,597	415,012
Cash flows from investing activities:		
Net proceeds from the sale of oil and gas properties	778,365	201,829
Capital expenditures	(624,969)	(492,794)
Acquisition of proved and unproved oil and gas properties	(87,389)	(21,853)
Acquisition deposit held in escrow	3,000	(49,000)
Net cash provided by (used in) investing activities	69,007	(361,818)
Cash flows from financing activities:		
Proceeds from credit facility	406,000	743,000
Repayment of credit facility	(406,000)	(945,000)
Debt issuance costs related to credit facility	—	(3,132)
Net proceeds from Senior Notes	—	492,397
Cash paid to repurchase Senior Notes	(2,344)	(29,904)
Net proceeds from Senior Convertible Notes	—	166,681
Cash paid for capped call transactions	—	(24,109)
Net proceeds from sale of common stock	1,738	533,266
Dividends paid	(5,563)	(3,404)
Other, net	(1,392)	(2,341)
Net cash provided by (used in) financing activities	(7,561)	927,454

Net change in cash and cash equivalents	432,043	980,648
Cash and cash equivalents at beginning of period	9,372	18
Cash and cash equivalents at end of period	$441,415	$980,666

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)
(in thousands)

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

	For the Nine Months Ended September 30,	
	2017	2016
Supplemental Cash Flow Information:		
Operating Activities:		
Cash paid for interest, net of capitalized interest [1]	$(124,443)	$(88,109)
Net cash (paid) refunded for income taxes	$(2,800)	$4,481
Investing Activities:		
Changes in capital expenditure accruals and other	$2,788	$(1,287)
Supplemental Non-Cash Investing Activities:		
Value of properties exchanged	$283,651	$733
Supplemental Non-Cash Financing Activities:		
Dividends declared, but not paid	$5,581	$4,343

(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.

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

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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, 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, 2016 (the "2016 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, 2017, and through the filing of this report. Certain prior period amounts have been reclassified to conform to the current presentation on the accompanying condensed consolidated financial statements.

Significant Accounting Policies

The significant accounting policies followed by the Company are set forth in Note 1 - Summary of Significant Accounting Policies to the Company's consolidated financial statements in its 2016 Form 10-K, and are supplemented by the notes to the unaudited condensed consolidated financial statements included in this report. These unaudited condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes included in the 2016 Form 10-K.

Recently Issued Accounting Standards

Effective January 1, 2017, the Company adopted, using various transition methods, Financial Accounting Standards Board ("FASB") Accounting Standards Update ("ASU") No. 2016-09, Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting ("ASU 2016-09"). ASU 2016-09 is meant to simplify certain aspects of accounting for share-based arrangements, including income tax effects, accounting for forfeitures, and net share settlements. The Company adopted the various applicable amendments, which are summarized as follows:

- On January 1, 2017, a $44.3 million cumulative-effect adjustment was made to retained earnings and a corresponding deferred tax asset was recorded for previously unrecognized excess tax benefits using a modified retrospective transition method. Additionally, going forward excess tax benefits will be presented in operating activities on the condensed consolidated statement of cash flows.
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- Also on January 1, 2017, the Company elected to change its policy to account for forfeitures of share-based payment awards as they occur, rather than applying an estimated forfeiture rate. This change was made using a modified retrospective transition method and resulted in an increase in additional paid-in capital of $1.1 million, a decrease in deferred tax assets of $0.4 million, and a net $0.7 million cumulative effect adjustment decrease to retained earnings. Under this new guidance, excess tax benefits and deficiencies from share-based payments impact the Company's effective tax rate between periods. Please refer to Note 4 - Income Taxes for additional discussion.

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606) ("ASU 2014-09"). Under the new standard, revenue is recognized when a customer obtains control of promised goods or services in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services. In addition, the standard requires disclosure of the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. The FASB issued several amendments to the standard which provided additional implementation guidance and deferred the effective date of ASU

2014-09. Based upon work performed as of September 30, 2017, and through the filing of this report, the Company does not currently anticipate a material impact to net income (loss) or cash flows. Further, the Company completed its initial assessment of certain pipeline gathering, transportation and gas processing agreements, and does not anticipate changes in how total revenues or total expenses will be recognized given where control transfers for these agreements. In addition, the Company is in the process of implementing appropriate changes to its business processes, systems, and controls to support the recognition and disclosure requirements of ASU 2014-09. The Company plans to adopt the guidance using the modified retrospective method on the effective date of January 1, 2018.

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842) ("ASU 2016-02"), which requires lessees to recognize a right-of-use asset and a lease liability for virtually all leases currently classified as operating leases. The Company is currently analyzing the impact this standard will have on the Company's contract portfolio, including non-cancelable leases, drilling rig contracts, pipeline gathering, transportation and gas processing agreements, and other existing arrangements. Further, the Company is evaluating current accounting policies, applicable systems, controls, and processes to support the potential recognition and disclosure changes resulting from ASU 2016-02. Based upon an initial assessment, adoption of ASU 2016-02 is expected to result in an increase in assets and liabilities recorded. The Company plans to adopt the guidance on the effective date of January 1, 2019.

In March 2017, the FASB issued ASU No. 2017-07, Compensation-Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost ("ASU 2017-07"). ASU 2017-07 requires presentation of service cost in the same line item(s) as other compensation costs arising from services rendered by employees during the period and presentation of the remaining components of net benefit cost in a separate line item, outside operating items. In addition, only the service cost component of net benefit cost is eligible for capitalization. The Company plans to adopt ASU 2017-07 on the effective date of January 1, 2018, with retrospective application of the service cost component and the other components of net benefit cost in the consolidated statements of operations and prospective application for the capitalization of the service cost component of net benefit costs in assets. While ASU 2017-07 will result in the Company reclassifying certain amounts from operating expenses to non-operating expenses upon adoption, the Company does not currently anticipate ASU 2017-07 will result in a material impact to the Company's consolidated financial statements or disclosures.

Other than as disclosed above or in the 2016 Form 10-K, there are no other ASUs 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, 2017, and through the filing of this report.

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

On March 10, 2017, the Company divested its outside-operated Eagle Ford shale assets, including its ownership interest in related midstream assets, for total cash received at closing, net of costs (referred to throughout this report as "net divestiture proceeds"), of $747.4 million. The Company finalized this divestiture subsequent to September 30, 2017, and recorded a final net gain of $396.8 million for the nine months ended September 30, 2017. These assets were classified as held for sale as of December 31, 2016.

The following table presents income (loss) before income taxes from the outside-operated Eagle Ford shale assets sold for the three and nine months ended September 30, 2017, and 2016. This divestiture is considered a disposal of a significant asset group.

	For the Three Months Ended September	For the Nine Months Ended September 30,

	30,			
	2017	2016	2017	2016
	(in thousands)			
Income (loss) before income taxes [1]	$ —	$ 22,116	$ 24,324	$ (251,451)

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(1) Income (loss) before income taxes reflects oil, gas, and NGL production revenue, less oil, gas, and NGL production expense, and depletion, depreciation, amortization, and asset retirement obligation liability accretion. Additionally, income (loss) before income taxes included impairment of proved properties expense of approximately $269.6 million for the nine months ended September 30, 2016.

During the first nine months of 2017, the Company divested certain non-core properties in its Rocky Mountain and Permian regions for net divestiture proceeds of $31.0 million.

During the third quarter of 2016, the Company divested certain non-core properties in its Rocky Mountain and Permian regions for net divestiture proceeds of $165.2 million. As of September 30, 2016, $23.6 million of accrued costs 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. The Company recorded a $22.4 million net gain on divestiture activity for the three months ended September 30, 2016, which was a result of closing divestitures in the Company's 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 net gain of $6.3 million recorded for the nine months ended September 30, 2016.

Assets Held for Sale

Assets are classified as held for sale when the Company commits to a plan to sell the assets and it is probable 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. When assets no longer meet the criteria of assets held for sale, they are measured at the lower of the carrying value of the assets before being classified as held for sale, adjusted for any depletion, depreciation, and amortization expense that would have been recognized, or the fair value at the date they are reclassified to assets held for use. Any gain or loss recognized on assets held for sale or on assets held for sale that are subsequently reclassified to assets held for use is reflected in the net gain (loss) on divestiture activity line item in the accompanying condensed consolidated statements of operations ("accompanying statements of operations"). As of September 30, 2017, there were $7.1 million of assets held for sale presented in the accompanying condensed consolidated balance sheets ("accompanying balance sheets").

During the nine months ended September 30, 2017, the Company recorded a $526.5 million write-down on its retained Divide County, North Dakota, assets previously held for sale, of which $359.6 million was recorded in the first quarter of 2017 based on an estimated fair value less selling costs and an additional $166.9 million write-down was recorded in the second quarter of 2017 based on market conditions that existed on the date the Company decided to retain the assets.

Acquisitions

During the first nine months of 2017, the Company acquired approximately 3,400 net acres of primarily unproved properties in Howard and Martin Counties, Texas, in multiple transactions for a total of $72.2 million of cash consideration. Under authoritative accounting guidance, these transactions were considered asset acquisitions and the properties were recorded based on the fair value of the total consideration transferred on the acquisition date and transaction costs were capitalized as a component of the cost of the assets acquired.

The Company finalized the 2016 acquisition of Midland Basin properties from Rock Oil Holdings, LLC (referred to as the "Rock Oil Acquisition") during the first quarter of 2017 by paying an additional $7.4 million of cash consideration, resulting in total consideration of approximately $1.0 billion paid after final closing adjustments. The Company finalized the 2016 acquisition of Midland Basin properties from QStar LLC and RRP-QStar, LLC (referred to as the "QStar Acquisition") during the third quarter of 2017 by paying an additional $7.3 million of cash consideration, with the majority of this payment being made in the first quarter of 2017, resulting in total consideration of approximately $1.6 billion paid after final closing adjustments. The Company funded these acquisitions with proceeds from divestitures, the Senior Convertible Notes issuance, the issuance of 6.75% Senior Notes due 2026 ("2026 Notes"), and equity offerings in 2016. Please refer to Note 5 - Long-Term Debt and Note 15 - Equity in the Company's 2016 Form 10-K for more information on the funding for these acquisitions. There were no material changes to the initial recorded basis of these proved and unproved properties acquired as a result of the final settlements.

Also, during the first nine months of 2017, the Company completed several non-monetary acreage trades of primarily unproved properties, in Howard and Martin Counties, Texas, resulting in the Company acquiring approximately 7,425 net acres in exchange for approximately 6,725 net acres with $283.7 million of value attributed to the properties assigned by the Company in such trades. These trades were recorded at carryover basis with no gain or loss recognized.

Note 4 - Income Taxes

The income tax benefit recorded for the three and nine months ended September 30, 2017, and 2016, differs from the amounts 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 excess tax benefits and deficiencies from share-based payment awards, state income taxes, changes in valuation allowances, and accumulated impacts of other smaller 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 for the three and nine months ended September 30, 2017, and 2016, consisted of the following:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in thousands)			
Current portion of income tax benefit (expense):				
Federal	$2,832	$—	$—	$—
State	(230)	(24)	(1,633)	(265)
Deferred portion of income tax benefit	36,668	23,756	67,458	314,770
Income tax benefit	$39,270	$23,732	$65,825	$314,505
Effective tax rate	30.6 %	36.7 %	32.8 %	36.1 %

On a year-to-date basis, a change in the Company's effective tax rate between reporting 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. As a result of adopting ASU 2016-09 on January 1, 2017, excess tax benefits and deficiencies from share-based payment awards impact the Company's effective tax rate between periods. As discussed in Note 7 - Compensation Plans, the Company settled various grants in the third quarter of 2017. As a result of these share-based award settlements, the Company recorded an $8.2 million excess tax deficiency in the third quarter of 2017 reducing the tax benefit and the tax benefit rate.

At the end of the third quarter 2017, the Company reevaluated various factors affecting deferred tax assets related to net operating losses and tax credits, and determined utilization would be appropriate. The change in the current portion of income tax benefit (expense) between periods reflects the effect of this determination. The Company is generally no longer subject to United States federal or state income tax examinations by tax authorities for years before 2013. Its 2003 to 2005 tax years have been reopened for net operating loss carryback claims and are currently under examination by the Internal Revenue Service (the "IRS"). During the quarter ended September 30, 2017, the Company received a $5.5 million refund in advance of the IRS completing its examination of the Company's claims.

Note 5 - Long-Term Debt

Credit Agreement

The Company's Fifth Amended and Restated Credit Agreement, as amended (the "Credit Agreement"), provides for a maximum loan amount of $2.5 billion and has a maturity date of December 10, 2019. On March 31, 2017, the Company entered into a Ninth Amendment to the Credit Agreement (the "Ninth Amendment") with its lenders. Pursuant to the Ninth Amendment, and as part of the regular, semi-annual borrowing base redetermination process, the borrowing base and aggregate lender commitments were reduced to $925 million primarily due to the sale of the Company's outside-operated Eagle Ford shale assets and the decrease in the value of the Company's proved reserves at

December 31, 2016. 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. As of the filing of this report, the second semi-annual redetermination for 2017 was in progress and is expected to be completed prior to year-end.

The Company must comply with certain financial and non-financial covenants under the terms of the Credit Agreement and was in compliance with all such covenants as of September 30, 2017, and through the filing of this report.

Interest and commitment fees are accrued based on a borrowing base utilization grid set forth in the Credit Agreement and presented in Note 5 - Long-Term Debt to the Company’s consolidated financial statements in its 2016 Form 10-K. Eurodollar loans accrue interest at the London Interbank Offered Rate, plus the applicable margin from the utilization table, and Alternate Base Rate and swingline loans accrue interest at the prime rate, plus the applicable margin from the utilization table. 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 following table presents the outstanding balance, total amount of letters of credit outstanding, and available borrowing capacity under the Credit Agreement as of October 26, 2017, September 30, 2017, and December 31, 2016:

	As of October 26, 2017	As of September 30, 2017	As of December 31, 2016
	(in thousands)		
Credit facility balance [1]	$—	$—	$—
Letters of credit [2]	200	200	200
Available borrowing capacity	924,800	924,800	1,164,800
Total aggregate lender commitment amount	$925,000	$925,000	$1,165,000

(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 totaled $3.5 million and $5.9 million as of September 30, 2017, and December 31, 2016, respectively.

(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, 2017, and December 31, 2016, consisted of the following:

	As of September 30, 2017			As of December 31, 2016		
	Principal Amount	Unamortized Deferred Financing Costs	Senior Notes, Net of Unamortized Deferred Financing Costs	Principal Amount	Unamortized Deferred Financing Costs	Senior Notes, Net of Unamortized Deferred Financing Costs
	(in thousands)					
6.50% Senior Notes due 2021 [1] [2]	$344,611	$ 2,830	$ 341,781	$346,955	$ 3,372	$ 343,583
6.125% Senior Notes due 2022 [2]	561,796	6,095	555,701	561,796	6,979	554,817
6.50% Senior Notes due 2023 [2]	394,985	3,889	391,096	394,985	4,436	390,549
5.0% Senior Notes due 2024	500,000	5,841	494,159	500,000	6,533	493,467
5.625% Senior Notes due 2025	500,000	6,940	493,060	500,000	7,619	492,381
6.75% Senior Notes due 2026 [3]	500,000	7,451	492,549	500,000	8,078	491,922
Total	$2,801,392	$ 33,046	$ 2,768,346	$2,803,736	$ 37,017	$ 2,766,719

(1) During the first quarter of 2017, the Company repurchased a total of $2.3 million in aggregate principal amount of 6.50% Senior Notes due 2021 in open market transactions at a slight premium. The Company canceled all of these repurchased Senior Notes upon cash settlement.

(2) During the first quarter of 2016, the Company repurchased a total of $46.3 million in aggregate principal amount of certain of its Senior Notes in open market transactions for a settlement amount of $29.9 million, excluding interest. The Company recorded a net gain on extinguishment of debt of approximately $15.7 million for the nine months ended September 30, 2016. This amount includes a gain of approximately $16.4 million associated with the discount realized upon repurchase, which was partially offset by approximately $0.7 million related to the acceleration of unamortized deferred financing costs. The Company canceled all of these repurchased Senior Notes upon cash settlement.

(3) On September 12, 2016, the Company issued 6.75% Senior Notes due September 15, 2026. The Company received net proceeds of $491.6 million after deducting paid and accrued fees. The net proceeds were used to partially fund the Rock Oil Acquisition that closed on October 4, 2016.

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 and was in compliance with all such covenants as of September 30, 2017, and through the filing 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.

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 Senior Convertible Notes mature on July 1, 2021, unless earlier converted. Holders may convert their Senior Convertible Notes at their option at any time prior to January 1, 2021, only under certain circumstances as outlined in the indenture governing the Senior Convertible Notes and in Note 5 – Long-Term Debt to the Company's consolidated financial statements in its 2016 Form 10-K. On or after January 1, 2021, until the maturity date, holders may convert their Senior Convertible Notes at any time. 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 would result in the Company settling the principal amount in cash with any excess value in shares of the Company's common stock. The Senior Convertible Notes were not convertible at the option of holders as of September 30, 2017, or through the filing of this report. Notwithstanding the inability to convert, the if-converted value of the Senior Convertible Notes as of September 30, 2017, did not exceed the principal amount.

Upon the issuance of the Senior Convertible Notes, the Company recorded $132.3 million as the initial carrying amount of the debt component, which approximated its fair value at issuance, and 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%. The $40.2 million 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 debt discount and debt-related issuance costs are amortized to the principal value of the Senior Convertible Notes as interest expense through the maturity date of July 1, 2021. Interest expense recognized on the Senior Convertible Notes related to the stated interest rate and amortization of the debt discount totaled $2.5 million and $7.4 million for the three and nine months ended September 30, 2017, respectively.

The net carrying amount of the liability component of the Senior Convertible Notes, as reflected on the accompanying balance sheets as of September 30, 2017, and December 31, 2016, consisted of the following:

	As of September 30, 2017	As of December 31, 2016
	(in thousands)	
Principal amount of Senior Convertible Notes	$172,500	$172,500
Unamortized debt discount	(32,048)	(37,513)

Unamortized deferred financing costs	(3,440)	(4,131)
Net carrying amount	$137,012	$130,856

The Company is subject to certain covenants under the indenture governing the Senior Convertible Notes and was in compliance with all such covenants as of September 30, 2017, and through the filing 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 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 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. The cap price of the capped call transactions is initially $60.00 per share. If the market price per share exceeds the cap price of the capped call transactions, there could be dilution or there would not be an offset of such potential cash payments.

Note 6 - Commitments and Contingencies

Commitments

During the first quarter of 2017, the Company completed the divestiture of its outside-operated Eagle Ford shale assets. Upon closing of the sale, the Company is no longer subject to gathering, processing, and transportation throughput commitments totaling 514 Bcf of gas, 52 MMBbl of oil, and 13 MMBbl of NGLs, or $501.9 million of the potential undiscounted deficiency payments as of December 31, 2016. As of September 30, 2017, the Company had total gathering, processing, transportation throughput, and purchase commitments with various third parties that require delivery of a minimum quantity of 850 Bcf of gas, 15 MMBbl of oil, and 25 MMBbl of water through 2028 and a minimum purchase quantity of 16 MMBbl of water by 2022. If the Company fails to deliver or purchase any product, as applicable, the aggregate undiscounted deficiency payments totaled approximately $445.0 million as of September 30, 2017. As of the filing of this report, the Company does not expect to incur any material shortfalls with regard to these commitments.

Additionally, the Company entered into new and amended drilling rig contracts during the first nine months of 2017 and subsequent to September 30, 2017. As of the filing of this report, the Company's drilling rig commitments totaled $30.4 million; however, if the Company terminated these rig contracts immediately, it would incur penalties of $17.5 million.

There were no other material changes in commitments during the first nine months of 2017. Please refer to Note 6 - Commitments and Contingencies to the Company's consolidated financial statements in its 2016 Form 10-K for additional discussion of the Company's 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. On July 7, 2017, Michael Lirette filed a Collective Action Complaint against the Company in the Southern District of Texas, claiming damages related to unpaid overtime wages under the Federal Fair Labor Standards Act. This case involves complex legal issues and uncertainties, a potentially large class of plaintiffs, and an alleged class period commencing in 2014. Because the proceedings are in the early stages, with discovery yet to be completed, the Company is unable to estimate what impact, if any, the action will have on its financial condition, results of operations, or cash flows.

Note 7 - Compensation Plans

Performance Share Units Under the Equity Incentive Compensation Plan

The Company grants performance share units ("PSUs") to eligible employees as part of its 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 PSUs are based on a combination of the Company's annualized Total Shareholder Return ("TSR") for the performance period and the relative performance of the Company's TSR compared with the annualized TSR of certain peer companies for the performance period. Compensation expense for PSUs is recognized within general and administrative and exploration expense over the vesting periods of the respective awards.

Total compensation expense recorded for PSUs for the three months ended September 30, 2017, and 2016, was $2.6 million and $2.3 million, respectively, and $6.8 million and $8.2 million for the nine months ended September 30, 2017, and 2016, respectively. As of September 30, 2017, there was $22.0 million of total unrecognized compensation expense related to non-vested PSU awards, which is being amortized through 2020.

A summary of the status and activity of non-vested PSUs for the nine months ended September 30, 2017, is presented in the following table:

	PSUs [1]	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year	828,923	$ 43.25
Granted	977,731	$ 15.86
Vested	(94,338)	$ 85.85
Forfeited	(168,658)	$ 46.30
Non-vested at end of quarter	1,543,658	$ 22.97

(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, 2017, the Company granted 977,731 PSUs with a fair value of $15.5 million as part of its regular annual long-term equity compensation program. These PSUs generally vest on the third anniversary of the date of the grant. Also, during this period, the Company settled PSUs that were granted in 2014 with no shares issued upon settlement as the grant settled at a zero multiplier.

Restricted Stock Units Under the Equity Incentive Compensation Plan

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

Total compensation expense recorded for RSUs was $2.9 million and $2.8 million for the three months ended September 30, 2017, and 2016, respectively, and $7.5 million and $9.3 million for the nine months ended September 30, 2017, and 2016, respectively. As of September 30, 2017, there was $22.8 million of total unrecognized compensation expense related to non-vested RSU awards, which is being amortized through 2020.

A summary of the status and activity of non-vested RSUs for the nine months ended September 30, 2017, is presented in the following table:

	RSUs	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year	604,116	$ 37.39
Granted	1,020,780	$ 16.64
Vested	(251,575)	$ 44.00
Forfeited	(102,183)	$ 28.43
Non-vested at end of quarter	1,271,138	$ 20.14

During the nine months ended September 30, 2017, the Company granted 1,020,780 RSUs with a fair value of $16.9 million. These RSUs generally 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, 2017, the Company settled 246,025 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 171,278 net shares of common stock upon settlement of the awards. The remaining 74,747 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 second quarter of 2017, the Company issued 71,573 shares of restricted common stock to its non-employee directors under the Company's Equity Incentive Compensation Plan, which fully vest on December 31, 2017. Also during the second quarter of 2017, the Company issued 8,794 RSUs to a non-employee director, which fully vest on December 31, 2017, and settle upon the earlier to occur of May 25, 2027, or the director resigning from the board of directors. The Company did not issue any director shares during the third quarter of 2017.

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 either the first or last day of the purchase period. The ESPP is intended to qualify under Section 423 of the Internal Revenue Code of 1986, as amended ("IRC"). There were 123,678 and 140,853 shares issued under the ESPP during the nine months ended September 30, 2017, and 2016, respectively. The fair value of ESPP grants is measured at the date of grant using the Black-Scholes option-pricing model.

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, 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,	
	2017	2016	2017	2016
	(in thousands)			
Service cost	$1,660	$2,050	$4,979	$6,150
Interest cost	673	727	2,017	2,181
Expected return on plan assets that reduces periodic pension benefit cost	(561)	(559)	(1,683)	(1,677)
Amortization of prior service cost	4	4	13	13
Amortization of net actuarial loss	324	396	973	1,187
Net periodic benefit cost	$2,100	$2,618	$6,299	$7,854

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 or the market-related value of assets are amortized over the average remaining service period of active participants.

Contributions

The Company contributed $7.0 million to the Qualified Pension Plan during the nine months ended September 30, 2017.

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 number of common shares outstanding for the respective period. Diluted net income or loss per common share is calculated by dividing adjusted net income or loss by the diluted weighted-average number of common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for this calculation consist primarily of non-vested RSUs, contingent PSUs, and shares into which the Senior Convertible Notes are convertible, which are measured using the treasury stock method.

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 due 2021. 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 would result in the Company settling the principal amount of the Senior Convertible Notes in cash and the excess conversion value in shares. However, the Company has not made this an irrevocable election and thereby reserves the right to settle the Senior Convertible Notes in any manner allowed under the indenture as business circumstances warrant. Shares of the Company's common stock traded at an average closing price below the $40.50 conversion price for the three and nine months ended September 30, 2017, and therefore, the Senior Convertible Notes had no dilutive impact. 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 (loss) per share, nor will they ever be, as they are 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 all periods presented, 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,	
	2017	2016	2017	2016
	(in thousands)			
Anti-dilutive	—	506	78	193

The following table sets forth the calculations of basic and diluted net loss per common share:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in thousands, except per share amounts)			
Net loss	$(89,112)	$(40,907)	$(134,585)	$(556,798)
Basic weighted-average common shares outstanding	111,575	78,468	111,366	71,574
Add: dilutive effect of non-vested RSUs and contingent PSUs	—	—	—	—
Add: dilutive effect of Senior Convertible Notes	—	—	—	—
Diluted weighted-average common shares outstanding	111,575	78,468	111,366	71,574

Basic net loss per common share	$(0.80)	$(0.52)	$(1.21)	$(7.78)
Diluted net loss per common share	$(0.80)	$(0.52)	$(1.21)	$(7.78)

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. As of September 30, 2017, all derivative counterparties were members of the Company’s credit facility lender group and all contracts were entered into for other-than-trading purposes. The Company’s commodity derivative contracts consist of swap and collar arrangements. 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, 2017, the Company had commodity derivative contracts outstanding as summarized in the tables below:

Oil Swaps

Contract Period	NYMEX WTI Volumes	Weighted-Average Contract Price
	(MBbls)	(per Bbl)
Fourth quarter 2017	1,510	$ 47.11
2018	6,272	$ 49.82
2019	1,940	$ 50.70
Total	9,722	

Oil Collars

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(MBbls)	(per Bbl)	(per Bbl)
Fourth quarter 2017	1,086	$ 47.51	$ 56.05
2018	5,030	$ 50.00	$ 58.07
2019	3,128	$ 50.00	$ 58.84
Total	9,244		

Oil Basis Swaps

Contract Period	Midland-Cushing Volumes	Weighted-Average Contract Price (1)
	(MBbls)	(per Bbl)
Fourth quarter 2017	1,856	$ (1.50)
2018	8,734	$ (1.27)
2019	3,963	$ (1.45)
Total	14,553	

(1) Represents the price differential between WTI prices at Midland, Texas and WTI prices at Cushing, Oklahoma.

Subsequent to September 30, 2017, the Company entered into Midland-Cushing basis swap contracts for 2018 for a total of 1.4 million Bbls of oil production at a contract price of ($0.33) per Bbl.

Natural Gas Swaps

Contract Period	Sold Volumes	Weighted-Average Contract Price	Purchased Volumes (1)	Weighted-Average Contract Price	Net Volumes
	(BBtu)	(per MMBtu)	(BBtu)	(per MMBtu)	(BBtu)
Fourth quarter 2017	22,001	$ 3.98	—	$ —	22,001
2018	102,900	$ 3.37	(30,606)	$ 4.27	72,294
2019	41,394	$ 3.76	(24,415)	$ 4.34	16,979
Total (2)	166,295		(55,021)		111,274

(1) During 2016, the Company restructured certain of its natural 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 other cash or other consideration was included as part of the restructuring.

(2) Total net volumes of natural gas swaps are comprised of IF El Paso Permian (1%), IF HSC (98%), and IF NNG Ventura (1%).

NGL Swaps

	OPIS Purity Ethane Mont Belvieu		OPIS Propane Mont Belvieu Non-TET		OPIS Normal Butane Mont Belvieu Non-TET		OPIS Isobutane Mont Belvieu Non-TET		OPIS Natural Gasoline Mont Belvieu Non-TET	
Contract Period	Volumes	Weighted-Average Contract Price	Volumes	Weighted-Average Contract Price	Volumes	Weighted-Average Contract Price	Volumes	Weighted-Average Contract Price	Volumes	Weighted-Average Contract Price
	(MBbls)	(per Bbl)	(MBbls)	(per Bbl)	(MBbls)	(per Bbl)	(MBbls)	(per Bbl)	(MBbls)	(per Bbl)
Fourth quarter 2017	966	$ 9.65	653	$ 24.24	214	$ 35.29	174	$ 35.60	203	$ 48.41
2018	4,017	$ 11.00	2,464	$ 24.74	391	$ 35.14	308	$ 34.72	427	$ 48.44
2019	3,112	$ 12.27	1,036	$ 26.49	—	$ —	—	$ —	—	$ —
2020	539	$ 11.13	—	$ —	—	$ —	—	$ —	—	$ —
Total	8,634		4,153		605		482		630	

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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 liability of $31.7 million as of September 30, 2017, and a net liability of $91.7 million as of December 31, 2016.

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

	As of September 30, 2017			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity contracts	Current assets	$63,685	Current liabilities	$87,791
Commodity contracts	Noncurrent assets	60,035	Noncurrent liabilities	67,676
Derivatives not designated as hedging instruments		$123,720		$155,467

	As of December 31, 2016			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity contracts	Current assets	$54,521	Current liabilities	$115,464
Commodity contracts	Noncurrent assets	67,575	Noncurrent liabilities	98,340
Derivatives not designated as hedging instruments		$122,096		$213,804

Offsetting of Derivative Assets and Liabilities

As of September 30, 2017, and December 31, 2016, 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.

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:

	Derivative Assets		Derivative Liabilities	
Offsetting of Derivative Assets and Liabilities	As of September 30, 2017	December 31, 2016	As of September 30, 2017	December 31, 2016
	(in thousands)			
Gross amounts presented in the accompanying balance sheets	$123,720	$ 122,096	$(155,467)	$ (213,804)
Amounts not offset in the accompanying balance sheets	(85,195)	(118,080)	85,195	118,080
Net amounts	$38,525	$ 4,016	$(70,272)	$ (95,724)

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in thousands)			
Derivative settlement (gain) loss:				
Oil contracts	$2,472	$(49,241)	$14,310	$(221,397)
Gas contracts	(24,088)	(10,096)	(63,345)	(82,588)
NGL contracts	8,524	1,841	19,633	(2,249)
Total derivative settlement gain	$(13,092)	$(57,496)	$(29,402)	$(306,234)
Total net derivative (gain) loss:				
Oil contracts	$45,874	$(733)	$(41,910)	$49,608
Gas contracts	(6,068)	(14,006)	(56,574)	24,460
NGL contracts	40,793	(13,298)	9,120	47,018
Total net derivative (gain) loss	$80,599	$(28,037)	$(89,364)	$121,086

Credit Related Contingent Features

As of September 30, 2017, and through the filing of this report, all of the Company's derivative counterparties were members of the Company's credit facility lender group. Under the Credit Agreement and derivative contracts, the Company is required to secure mortgages on assets having a value equal 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, 2017:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives (1)	$—	$123,720	$ —
Liabilities:			
Derivatives (1)	$—	$155,467	$ —

(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, 2016:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives (1)	$—	$122,096	$—
Total property and equipment, net (2)	$—	$—	$88,205
Liabilities:			
Derivatives (1)	$—	$213,804	$—

(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. Additionally, all of the Company’s derivative counterparties are members of the Company’s credit facility lender group.

Please refer to Note 10 - Derivative Financial Instruments above and to Note 11 - Fair Value Measurements in the Company’s 2016 Form 10-K for more information regarding the Company’s derivative instruments.

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

The Company did not have property and equipment measured at fair value within the accompanying balance sheets as of September 30, 2017. Property and equipment, net measured at fair value totaled $88.2 million as of December 31, 2016, and primarily consisted of the Company’s Powder River Basin assets, which were impaired at year-end as a result of downward performance reserve revisions.

Proved oil and gas properties. Proved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication the carrying costs may not be recoverable. The Company uses Level 3 inputs and the income valuation technique, which converts future amounts to a single present value amount, to measure the fair value of proved properties through an application of discount rates and price forecasts 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 the rates used ranged from 10 percent to 15 percent based on the reservoir specific weightings of future estimated proved and unproved cash flows as of September 30, 2017, and December 31, 2016. The Company believes the discount rates are representative of current market conditions and consider 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.

The Company did not recognize any material impairment of proved properties expenses for the three or nine months ended September 30, 2017, or for the three months ended September 30, 2016. The Company recorded impairment of proved properties expense of $277.8 million for the nine months ended September 30, 2016, primarily related to the decline in proved and risk-adjusted probable and possible reserve expected cash flows from the Company’s outside-operated Eagle Ford shale assets, driven by commodity price declines during the first quarter of 2016. These properties were sold during the first quarter of 2017. Please refer to Note 3 - Divestitures, Assets Held for Sale, and Acquisitions for more information regarding divestiture activity.

Unproved oil and gas properties. 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: remaining lease terms, future development plans, risk weighted potential resource recovery, estimated reserve values, and estimated acreage value based on price(s) received for similar, recent acreage transactions by the Company or other market participants.

There were no material abandonments or impairments of unproved properties expenses for the three or nine months ended September 30, 2017 or 2016.

Oil and gas properties held for sale. Proved and unproved properties and other property and equipment classified as held for sale, including the corresponding asset retirement obligation liability, are valued using a market approach based on an estimated net selling price, as evidenced by the most current bid prices received from third parties, if available, or by recent, comparable market transactions. If an estimated selling price is not available, the Company utilizes the various income valuation techniques discussed above. When assets no longer meet the criteria of assets held for sale, they are measured at the lower of the carrying value of the assets before being classified as held for sale, adjusted for any depletion, depreciation, and amortization expense that would have been recognized, or the fair value at the date they are reclassified to assets held for use.

There were no material assets held for sale that were recorded at fair value as of September 30, 2017. However, for the nine months ended September 30, 2017, the Company recorded a $526.5 million write-down on its Divide County, North Dakota, assets previously held for sale, of which $359.6 million was recorded in the first quarter of 2017 based on an estimated fair value less selling costs and $166.9 million was recorded in the second quarter of 2017 based on market conditions that existed on the date the Company decided to retain the assets. Please refer to Note 3 - Divestitures, Assets Held for Sale, and Acquisitions for additional discussion.

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. These notes were not presented at fair value on the accompanying balance sheets as of September 30, 2017, or December 31, 2016, as they were recorded at carrying value, net of any unamortized discounts and deferred financing costs. Please refer to Note 5 - Long-Term Debt for additional discussion.

	As of September 30, 2017		As of December 31, 2016	
	Principal Amount	Fair Value	Principal Amount	Fair Value
	(in thousands)			
6.50% Senior Notes due 2021	$344,611	$349,780	$346,955	$354,546
6.125% Senior Notes due 2022	$561,796	$565,830	$561,796	$570,925
6.50% Senior Notes due 2023	$394,985	$397,947	$394,985	$403,134
5.0% Senior Notes due 2024	$500,000	$471,660	$500,000	$475,975
5.625% Senior Notes due 2025	$500,000	$477,350	$500,000	$485,000
6.75% Senior Notes due 2026	$500,000	$502,500	$500,000	$516,565
1.50% Senior Convertible Notes due 2021	$172,500	$163,240	$172,500	$202,189

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

This discussion includes forward-looking statements. Please refer to Cautionary Information about Forward-Looking Statements at the end of this item for important information about 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 be a premier operator of top tier assets. We seek to maximize the value of our assets by applying industry leading technology and outstanding operational execution. Our portfolio is comprised of unconventional resource prospects with prospective drilling opportunities, which we believe provide for long-term production and reserves growth. We focus on achieving high full-cycle economic returns on our investments and maintaining a simple, strong balance sheet.

We currently have material core producing assets and acreage positions in the Midland Basin and Eagle Ford shale in Texas, as well as producing assets and material acreage positions in the Powder River Basin in Wyoming, and the Bakken/Three Forks play in North Dakota. During 2016, and continuing into 2017, we made several proved and unproved property acquisitions and trades in the Midland Basin, while divesting non-core assets in other areas. By actively managing our asset portfolio in this way, we are seeking to concentrate our investments in areas with the highest economic returns and provide value through accelerated development activity.

Third Quarter 2017 Highlights and Outlook for the Remainder of 2017

Our priorities for 2017, as set at the beginning of the year, were to:

- demonstrate the value of our 2016 and 2017 acquisitions in the Midland Basin;
- generate high margin production growth from our operated acreage positions in the Midland Basin and Eagle Ford shale;
- successfully execute the sale of our outside-operated Eagle Ford shale and Divide County, North Dakota, assets; and
- reduce our outstanding debt.

With respect to our 2017 priorities, we have focused on demonstrating the significant value potential of our Midland Basin position and coring up this position in order to maximize long-term growth. We successfully closed the sale of our outside-operated Eagle Ford shale assets in the first quarter of 2017 for net divestiture proceeds of $747.4 million. Proceeds from this divestiture continue to provide us with significant liquidity and will support funding our capital program for the remainder of the year. During the second quarter of 2017, we made the decision to retain our Divide County, North Dakota, assets as valuations in the sales process did not reach our expectations. We will continue to use cash flows from our Divide County, North Dakota, assets to fund higher margin production growth projects within our portfolio.

We expect our capital program for 2017, excluding acquisitions, to be approximately $875 million. We have been concentrating our capital on our highest return programs and have been operating at strong performance levels to generate higher company-wide margins and cash flow growth while creating value for our stockholders. Please refer to Overview of Liquidity and Capital Resources below for additional discussion on how we expect to fund our 2017 capital program.

Operational Activities. In our Midland Basin program, we operated seven drilling rigs and three completion crews during the third quarter of 2017. Of these seven drilling rigs, five were focused on delineating and developing the

Lower Spraberry and Wolfcamp A and B shale intervals on our acreage position in Howard and Martin Counties, Texas, and the other two drilling rigs focused on developing the Wolfcamp A and B and Lower Spraberry shale intervals on our Sweetie Peck property in Upton and Midland Counties, Texas. Subsequent to September 30, 2017, we added a fourth completion crew and entered into an agreement to add an eighth drilling rig, which we expect to begin operating during the fourth quarter of 2017. We expect approximately 80 percent of our 2017 capital program to be dedicated to our Midland Basin program.

During the first nine months of 2017, we acquired approximately 3,400 net acres of primarily unproved properties in the Midland Basin in multiple transactions totaling $72.2 million of cash consideration. Additionally, we completed several non-monetary acreage trades consisting primarily of unproved acreage of approximately 7,425 net acres in exchange for approximately 6,725 net acres in Howard and Martin Counties, Texas with $283.7 million of value attributed to the properties that we assigned in such trades. These trades, which we recorded at carryover basis with no gain or loss recognized, increased our working interest in existing drilling units and also provide us the opportunity to drill longer lateral wells.

In our Eagle Ford shale program, we began the third quarter of 2017 running one drilling rig and added one drilling rig during the quarter. We remain focused on drilling and completion optimization and meeting lease obligations. We expect approximately 20 percent of our 2017 capital program to be dedicated to our Eagle Ford shale program.

In September 2017, we entered into a joint venture agreement with a third party to drill 16 wells and complete 23 wells in a focused portion of our Eagle Ford North area. This partnership allows us to use third party resources to test cutting edge technology, accelerate the capture of technical data, and hold acreage in this area, potentially expanding economic drilling inventory and acreage value. Moreover, we expect this partnership will result in further optimizations outside of the joint venture area, enhancing the overall value of our Eagle Ford asset. The objectives of this agreement are similar to our highly successful, ongoing joint venture arrangement in the Powder River Basin discussed below. Per the terms of the agreement, our working interest was reduced in seven wells completed during the third quarter of 2017. The joint venture is expected to result in drilling six carried wells in the joint venture area in the fourth quarter of 2017.

In our Powder River Basin program, we continued running one drilling rig during the third quarter of 2017 under an acquisition and development funding agreement with a third party, pursuant to which the third party is carrying our drilling and completion costs.

Costs Incurred in Oil and Gas Producing Activities. Costs incurred in oil and gas property acquisition, exploration, and development activities, whether capitalized or expensed, totaled $226.6 million and $741.6 million for the three and nine months ended September 30, 2017, respectively. Costs incurred in 2017 were primarily in our Midland Basin and operated Eagle Ford shale program. Of our total costs incurred for the nine months ended September 30, 2017, $76.6 million related to property acquisitions, primarily unproved, in Howard and Martin Counties, Texas, which were incurred in the first half of 2017. Additionally, we completed several non-monetary acreage trades in the Midland Basin during the first nine months of 2017 totaling $283.7 million of value attributed to the properties surrendered. This non-monetary consideration is not reflected in the costs incurred amounts presented above.

Drilling and Completion Activity. The table below provides a summary of changes in our drilled but not completed well count and current year drilling and completion activity in our operated programs during the nine months ended September 30, 2017:

	Midland Basin		Eagle Ford Shale		Bakken/Three Forks		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Wells drilled but not completed at December 31, 2016	17	17	47	47	20	17	84	81
Wells drilled	19	19	5	5	—	—	24	24
Wells completed	(16)	(16)	(17)	(17)	—	—	(33)	(33)
Wells drilled but not completed at March 31, 2017	20	20	35	35	20	17	75	72
Wells drilled	24	23	6	6	—	—	30	29
Wells completed	(9)	(9)	(14)	(14)	—	—	(23)	(23)
Wells drilled but not completed at June 30, 2017	35	34	27	27	20	17	82	78
Wells drilled	29	25	6	6	—	—	35	31
Wells completed	(23)	(23)	(7)	(4)	—	—	(30)	(27)
Other [1]	—	—	—	(3)	—	—	—	(3)
Wells drilled but not completed at September 30, 2017	41	36	26	26	20	17	87	79

(1) Reflects net working interest changes resulting from the Eagle Ford North joint venture agreement discussed above.

Production Results. The table below provides a regional breakdown of our production for the three and nine months ended September 30, 2017:

	Permian		South Texas & Gulf Coast		Rocky Mountain		Total	
	Three Months Ended	Nine Months Ended	Three Months Ended	Nine Months Ended	Three Months Ended	Nine Months Ended	Three Months Ended	Nine Months Ended
Oil (MMBbl)	2.3	5.6	0.4	1.6	0.7	2.6	3.4	9.8
Gas (Bcf)	3.9	10.1	24.2	83.8	1.0	3.1	29.1	97.0
NGLs (MMBbl)	—	—	2.4	8.0	—	0.1	2.4	8.1
Equivalent (MMBOE)	3.0	7.3	6.7	23.5	1.0	3.2	10.7	34.1
Avg. daily equivalents (MBOE/d)	32.3	26.9	73.3	86.2	10.4	11.8	116.0	124.9
Relative percentage	28 %	22 %	63 %	69 %	9 %	9 %	100 %	100 %

Note: Amounts may not calculate due to rounding.

Production on an equivalent basis decreased 25 percent and 19 percent for the three and nine months ended September 30, 2017, compared with the same periods in 2016. Production declines were primarily a result of property divestitures, which occurred in the last half of 2016 and the first quarter of 2017, specifically our Raven/Bear Den and outside-operated Eagle Ford shale assets. These declines were partially offset by increased production in our Permian region. The production decline also includes the effects of Hurricane Harvey of approximately 0.2 MMBOE due to intermittent curtailments in certain production due to downstream, third-party facilities that were impacted by the storm. All of our production, drilling, and completion operations have since returned to normal. When excluding production from all assets sold in 2016 and 2017, production from retained assets increased approximately seven percent and 11 percent for the three and nine months ended September 30, 2017, compared with the same periods in 2016, respectively, which is being driven primarily by the ramp up in our Midland Basin development program. Please refer to A Three-Month and Nine-Month Overview of Selected Production and Financial Information, Including Trends and Comparison of Financial Results and Trends Between the Three Months and Nine Months Ended September 30, 2017, and 2016 below for additional discussion on production.

Financial Results. In the third quarter of 2017, we had the following financial results:

- We recorded a net loss of $89.1 million, or $0.80 per diluted share, for the three months ended September 30, 2017, compared with a net loss of $40.9 million, or $0.52 per diluted share, for the same period in 2016. Please refer to Comparison of Financial Results and Trends Between the Three Months and Nine Months Ended September 30, 2017, and 2016 below for additional discussion regarding the components of net loss for each period presented.

- We had net cash provided by operating activities of $128.5 million for the three months ended September 30, 2017, compared with $158.1 million for the same period in 2016. Please refer to Overview of Liquidity and Capital Resources below for additional discussion of our sources and uses of cash.

- Adjusted EBITDAX, a non-GAAP financial measure, for the three months ended September 30, 2017, was $164.5 million, compared with $205.1 million for the same period in 2016. Please refer to Non-GAAP Financial Measures below for additional discussion, including our definition of adjusted EBITDAX and reconciliations of our net 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. 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. 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.

The following table summarizes commodity price data, as well as the effects of derivative settlements, for the third and second quarters of 2017, as well as the third quarter of 2016:

	For the Three Months Ended		
	September 30, 2017	June 30, 2017	September 30, 2016
Crude Oil (per Bbl):			
Average NYMEX contract monthly price	$48.20	$48.28	$ 44.94
Realized price, before the effect of derivative settlements	$45.20	$44.30	$ 38.81
Effect of oil derivative settlements	$(0.73)	$(0.94)	$ 11.34
Natural Gas:			
Average NYMEX monthly settle price (per MMBtu)	$3.00	$3.18	$ 2.81
Realized price, before the effect of derivative settlements (per Mcf)	$2.96	$2.99	$ 2.71
Effect of natural gas derivative settlements (per Mcf)	$0.83	$0.64	$ 0.27
NGLs (per Bbl):			
Average OPIS price [1]	$27.55	$24.11	$ 19.74
Realized price, before the effect of derivative settlements	$22.40	$19.71	$ 16.58
Effect of NGL derivative settlements	$(3.54)	$(0.98)	$ (0.51)

(1) Average OPIS prices per barrel of NGL, historical or strip, are based on a product mix of 37% Ethane, 32% Propane, 14% Natural Gasoline, 11% Normal Butane, and 6% Isobutane 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.

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 various regions of the world as well as the relative strength of the dollar compared to other currencies. Oil markets have strengthened due to recent inventory drawdowns, but we expect oil prices to remain volatile due to uncertainty in global demand and easy access to new supply such as increases in oil production from US shale producers. Oil prices began to increase at the end of 2016 as a result of the Organization of Petroleum Exporting Countries ("OPEC") and several non-OPEC exporting countries agreeing to cut production. While participating countries have largely adhered to agreed upon production cuts, uncertainty remains concerning whether these cuts will be sustained.

Natural gas pricing has improved over the last year, largely as a result of demand growth from gas fired power generation, gas exports to Mexico, and LNG exports. We expect prices to remain near current levels in the near term as drilling rigs in operation increased through the first half of 2017 leading to increased supply. We also expect prices to fluctuate with changes in demand resulting from the weather.

NGL prices have also improved over the last year due to oil and natural gas price recovery, increased exports of ethane and propane, and new processing plants. We expect NGL prices to continue to benefit from increased demand from export and petrochemical markets while being offset by increased drilling activity.

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, 2017, and September 30, 2017:

	As of October 26, 2017	As of September 30, 2017
NYMEX WTI oil (per Bbl)	$ 52.87	$ 51.99
NYMEX Henry Hub gas (per MMBtu)	$ 3.02	$ 3.05

OPIS NGLs (per Bbl)	$ 29.61	$ 28.67

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 prices while also setting a price floor for a portion of our oil 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.

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, 2017	June 30, 2017	March 31, 2017	December 31, 2016
	(in millions, except for production data)			
Production (MMBOE)	10.7	11.3	12.1	13.4
Oil, gas, and NGL production revenue	$294.5	$284.9	$333.2	$346.3
Oil, gas, and NGL production expense	$122.7	$124.4	$138.0	$151.9
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$134.6	$153.2	$137.8	$171.6
Exploration	$14.2	$13.1	$12.0	$23.7
General and administrative	$27.9	$28.5	$29.2	$33.3
Net income (loss)	$(89.1)	$(119.9)	$74.4	$(200.9)

Note: Amounts may not calculate due to rounding.

Selected Performance Metrics

	For the Three Months Ended			
	September 30, 2017	June 30, 2017	March 31, 2017	December 31, 2016
Average net daily production equivalent (MBOE per day)	116.0	124.6	134.4	145.6
Lease operating expense (per BOE)	$4.81	$4.11	$3.82	$3.67
Transportation costs (per BOE)	$5.24	$5.71	$5.88	$6.39
Production taxes as a percent of oil, gas, and NGL production revenue	4.2 %	4.0 %	4.2 %	4.3 %
Ad valorem tax expense (per BOE)	$0.29	$0.16	$0.55	$0.17
Depletion, depreciation, amortization, and asset retirement obligation liability accretion (per BOE)	$12.61	$13.52	$11.39	$12.81
General and administrative (per BOE)	$2.61	$2.51	$2.42	$2.49

Note: Amounts may not calculate due to rounding.

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A Three-Month and Nine-Month Overview of Selected Production and Financial Information, Including Trends

	For the Three Months Ended September 30, 2017	2016	Amount Change Between Periods	Percent Change Between Periods	For the Nine Months Ended September 30, 2017	2016	Amount Change Between Periods	Percent Change Between Periods
Net production volumes [1]								
Oil (MMBbl)	3.4	4.3	(0.9)	(21)%	9.8	12.6	(2.7)	(22)%
Gas (Bcf)	29.1	37.1	(8.0)	(22)%	97.0	111.7	(14.7)	(13)%
NGLs (MMBbl)	2.4	3.6	(1.2)	(34)%	8.1	10.7	(2.6)	(24)%
Equivalent (MMBOE)	10.7	14.2	(3.5)	(25)%	34.1	41.9	(7.8)	(19)%
Average net daily production [1]								
Oil (MBbl per day)	37.1	47.2	(10.1)	(21)%	36.1	45.9	(9.8)	(21)%
Gas (MMcf per day)	316.1	403.0	(86.9)	(22)%	355.4	407.8	(52.4)	(13)%
NGLs (MBbl per day)	26.2	39.5	(13.3)	(34)%	29.6	39.0	(9.4)	(24)%
Equivalent (MBOE per day)	116.0	153.9	(37.9)	(25)%	124.9	152.9	(27.9)	(18)%
Oil, gas, and NGL production revenue (in millions)								
Oil production revenue	$ 154.2	$ 168.6	$ (14.4)	(9)%	$ 450.7	$ 436.0	$ 14.7	3 %
Gas production revenue	86.3	100.4	(14.1)	(14)%	289.2	236.7	52.5	22 %
NGL production revenue	54.0	60.2	(6.2)	(10)%	172.7	159.4	13.3	8 %
Total	$ 294.5	$ 329.2	$ (34.7)	(11)%	$ 912.6	$ 832.1	$ 80.5	10 %
Oil, gas, and NGL production expense (in millions)								
Lease operating expense	$ 51.4	$ 46.5	$ 4.9	11 %	$ 144.1	$ 144.7	$ (0.6)	— %
Transportation costs	55.9	88.4	(32.5)	(37)%	191.7	254.8	(63.1)	(25)%
Production taxes	12.4	14.7	(2.3)	(16)%	37.8	37.0	0.8	2 %
Ad valorem tax expense	3.0	2.9	0.1	3 %	11.5	9.2	2.3	25 %
Total	$ 122.7	$ 152.5	$ (29.8)	(20)%	$ 385.1	$ 445.7	$ (60.6)	(14)%
Realized price (before the effect of derivative settlements)								
Oil (per Bbl)	$ 45.20	$ 38.81	$ 6.39	16 %	$ 45.77	$ 34.69	$ 11.08	32 %
Gas (per Mcf)	$ 2.96	$ 2.71	$ 0.25	9 %	$ 2.98	$ 2.12	$ 0.86	41 %
NGLs (per Bbl)	$ 22.40	$ 16.58	$ 5.82	35 %	$ 21.36	$ 14.91	$ 6.45	43 %
Per BOE	$ 27.59	$ 23.25	$ 4.34	19 %	$ 26.76	$ 19.87	$ 6.89	35 %
Per BOE data [1]								
Production costs:								
Lease operating expense	$ 4.81	$ 3.29	$ 1.52	46 %	$ 4.22	$ 3.46	$ 0.76	22 %
Transportation costs	$ 5.24	$ 6.24	$ (1.00)	(16)%	$ 5.62	$ 6.08	$ (0.46)	(8)%
Production taxes	$ 1.15	$ 1.04	$ 0.11	11 %	$ 1.11	$ 0.88	$ 0.23	26 %
Ad valorem tax expense	$ 0.29	$ 0.21	$ 0.08	38 %	$ 0.34	$ 0.22	$ 0.12	55 %
General and administrative	$ 2.61	$ 2.31	$ 0.30	13 %	$ 2.51	$ 2.22	$ 0.29	13 %
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$ 12.61	$ 13.70	$ (1.09)	(8)%	$ 12.48	$ 14.78	$ (2.30)	(16)%
Derivative settlement gain [2]	$ 1.23	$ 4.06	$ (2.83)	(70)%	$ 0.86	$ 7.31	$ (6.45)	(88)%
Earnings per share information								
Basic net loss per common share	$ (0.80)	$ (0.52)	$ (0.28)	(54)%	$ (1.21)	$ (7.78)	$ 6.57	84 %
Diluted net loss per common share	$ (0.80)	$ (0.52)	$ (0.28)	(54)%	$ (1.21)	$ (7.78)	$ 6.57	84 %
Basic weighted-average common shares outstanding (in thousands)	111,575	78,468	33,107	42 %	111,366	71,574	39,792	56 %

Diluted weighted-average common shares outstanding (in thousands)	111,575	78,468	33,107	42	%	111,366	71,574	39,792	56	%

(1) Amount and percentage changes may not calculate due to rounding.
(2) Derivative settlements for the three and nine months ended September 30, 2017, and 2016, respectively, are included within the net derivative (gain) loss line item in the accompanying statements of operations.

We present per BOE information because we use this information to evaluate our performance relative to our peers and to identify and measure trends we believe may require additional analysis. Average net daily production for the three and nine months ended September 30, 2017, decreased 25 percent and 18 percent, respectively, compared with the same periods in 2016. These decreases are primarily due to the divestitures of properties across our regions in the last half of 2016 and the first quarter of 2017, specifically the divestitures of our Raven/Bear Den and outside-operated Eagle Ford shale assets. When excluding production from all assets sold in 2016 and 2017, daily production from retained assets increased approximately seven percent and 11 percent for the three and nine months ended September 30, 2017, compared with the same periods in 2016, respectively, which is being driven primarily by the ramp up in our Midland Basin development program. Overall, we expect a decrease in production for full-year 2017 compared with full-year 2016. Please refer to Comparison of Financial Results and Trends Between the Three Months and Nine Months Ended September 30, 2017, and 2016 below for additional discussion.

Changes in production volumes, revenues, and costs reflect the macro-economic effects on commodity prices and our transitioning portfolio. Our realized price before the effects of derivative settlements on a per BOE basis for the three and nine months ended September 30, 2017, increased 19 percent and 35 percent, respectively, compared with the same periods in 2016. Commodity prices were at multi-year lows in early 2016, began to recover in the second half of 2016, and fluctuated throughout the first nine months of 2017. For the three and nine months ended September 30, 2017, we had $1.23 and $0.86 per BOE gains on the settlement of our derivative contracts, respectively, which compares with gains of $4.06 and $7.31 per BOE for the three and nine months ended September 30, 2016, respectively. Despite commodity prices being low in the first half of 2016, we have experienced a slight increase in our realized price after the effect of derivative settlements for the three and nine months ended September 30, 2017, compared with the same periods in 2016.

Lease operating expense (“LOE”) on a per BOE basis increased 46 percent and 22 percent, respectively, for the three and nine months ended September 30, 2017, compared with the same periods in 2016. The increase in LOE on a per BOE basis was driven primarily by the divestiture of our outside-operated Eagle Ford shale assets in the first quarter of 2017, which had lower average lifting costs, as well as higher unanticipated LOE costs in our operated Eagle Ford shale program during the three months ended September 30, 2017. We expect LOE on a per BOE basis to be higher in 2017 compared with 2016 due to the change in our asset base and increasing oil production, which has higher LOE, as a percentage of our total product mix. However, LOE may also vary by quarter depending upon the level of workover activity, total production, and our overall product mix.

Transportation expense on a per BOE basis decreased 16 percent and eight percent, respectively, for the three and nine months ended September 30, 2017, compared with the same periods in 2016, primarily due to the sale of our outside-operated Eagle Ford shale assets in the first quarter of 2017. In general, we expect transportation costs on a per BOE basis to decrease in 2017 as our Midland Basin assets become a larger portion of our production mix. The majority of our Midland Basin production is sold at the wellhead under current contracts, and therefore, there is minimal transportation expense separately recorded on the accompanying statements of operations.

Production taxes on a per BOE basis increased 11 percent and 26 percent, respectively, for the three and nine months ended September 30, 2017, compared with the same periods in 2016, due to an increase in our realized price before the effect of derivative settlements, which was partially offset by a decrease in our production tax rate. Our production tax rate for the three and nine months ended September 30, 2017, was 4.2 percent and 4.1 percent, respectively, compared with 4.5 percent and 4.4 percent, respectively, for the same periods in 2016. This decrease in our company-wide production tax rate is primarily a result of divesting our Raven/Bear Den and other Rocky Mountain assets, which were taxed at higher rates than our Texas assets. We generally expect production tax expense to trend with oil, gas, and NGL production revenue on an absolute and per BOE basis. Product mix, the location of production, and incentives to encourage oil and gas development can also impact the amount of production tax we recognize.

Ad valorem tax expense on a per BOE basis increased 38 percent and 55 percent, respectively for the three and nine months ended September 30, 2017, compared with the same periods in 2016, as a result of changes in our asset and production base and increased commodity price assumptions used in 2017 property tax valuations. The majority of our ad valorem tax expense is related to our Texas properties. As a result of acquiring producing properties in Texas and divesting producing properties in our Rocky Mountain region, and with higher commodity prices used in the 2017 valuations than in 2016 valuations, we expect ad valorem tax expense on an absolute and per BOE basis to be higher for full-year 2017 compared to 2016.

General and administrative ("G&A") expense on a per BOE basis increased 13 percent for both the three and nine months ended September 30, 2017, compared with the same periods in 2016, due to the decrease in production volumes as a result of recent divestitures. We expect G&A expense on an absolute basis to remain relatively flat in 2017 compared with 2016 as reduced headcount is expected to be offset by increases in base and short-term incentive compensation. However, we expect an overall increase in G&A expense on a per BOE basis in 2017 due to the decrease in production volumes.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion ("DD&A") expense on a per BOE basis decreased eight percent and 16 percent, respectively, for the three and nine months ended September 30, 2017, compared with the same periods in 2016, as a result of divested assets, specifically our higher cost Raven/Bear Den assets sold at the end of 2016, our outside-operated Eagle Ford shale assets that were held for sale prior to being sold in the first quarter of 2017, and our Divide County, North Dakota, assets that were classified as held for sale during the first quarter of 2017 and for a portion of the second quarter of 2017. These assets were not depleted while classified as held for sale. Our DD&A rate fluctuates as a result of impairments, planned and closed divestitures, and changes in the mix of our production and the underlying proved reserve volumes. In general, we expect DD&A expense on a per BOE basis to be lower for full-year 2017 than full-year 2016 due to selling our higher cost Raven/Bear Den assets in late 2016 and the impact of large asset packages held for sale during the first quarter of 2017.

Please refer to Comparison of Financial Results and Trends Between the Three Months and Nine Months Ended September 30, 2017, and 2016 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 our basic and diluted net loss per common share calculations. Our basic and diluted weighted-average common share count increased for the three and nine months ended September 30, 2017, compared with the same periods in 2016, due primarily to public and private common stock offerings made in the last half of 2016.

Comparison of Financial Results and Trends Between the Three Months and Nine Months Ended September 30, 2017, and 2016

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

The following table presents the regional changes in our oil, gas, and NGL production, production revenues, and production costs between the three and nine months ended September 30, 2017, and 2016:

	Average Net Daily Production Increase (Decrease)		Production Revenues Increase (Decrease)		Production Costs Increase (Decrease)	
	Three Months Ended	Nine Months Ended	Three Months Ended	Nine Months Ended	Three Months Ended	Nine Months Ended
	(MBOE/d)		(in millions)		(in millions)	
Permian	21.6	18.2	$87.3	$228.4	$23.2	$56.1
South Texas & Gulf Coast	(40.1)	(28.4)	(66.0)	(35.3)	(30.5)	(57.3)
Rocky Mountain	(19.4)	(17.7)	(56.0)	(112.6)	(22.5)	(59.4)
Total	(37.9)	(27.9)	$(34.7)	$80.5	$(29.8)	$(60.6)

For the three months ended September 30, 2017, compared with the same period in 2016, the 25 percent decrease in net equivalent production volumes, primarily due to recent divestitures, was partially offset by a 19 percent increase in realized prices on a per BOE basis resulting in an overall 11 percent decrease in oil, gas, and NGL production revenues. For the nine months ended September 30, 2017, compared with the same period in 2016, the 35 percent increase in realized prices on a per BOE basis was partially offset by a 19 percent decrease in net equivalent production volumes, primarily due to recent divestitures, resulting in a 10 percent increase in oil, gas, and NGL production revenues. Production costs for the three and nine months ended September 30, 2017, compared with the same periods in 2016, decreased 20 percent and 14 percent, respectively, due to the decrease in net equivalent production volumes, as discussed above. Partially offsetting the decrease in production volumes, revenues, and costs in our South Texas & Gulf Coast and Rocky Mountain regions due to recent divestitures was an increase in production volumes, revenues, and costs in our Permian region in 2017 due to increased drilling and completion activity in our Midland Basin development program. Please refer to A Three-Month and Nine-Month Overview of Selected Production and Financial Information, Including Trends above for discussion of trends on a per BOE basis.

Net gain (loss) on divestiture activity

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Net gain (loss) on divestiture activity	$(1.9)	$22.4	$(131.6)	$3.4

The $131.6 million net loss on divestiture activity recorded for the nine months ended September 30, 2017, was primarily the result of a $526.5 million write-down on our retained Divide County, North Dakota, assets previously held for sale, which was partially offset by a $396.8 million net gain recorded on the sale of our outside-operated Eagle Ford shale assets during the first quarter of 2017.

The $22.4 million net gain on divestiture activity recorded for the three months ended September 30, 2016, was 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 net gain for the nine months ended September 30, 2016.

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

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$134.6	$194.0	$425.6	$619.2

DD&A expense decreased 31 percent for both the three and nine months ended September 30, 2017, compared with the same periods in 2016, due to the decline in our production volumes and the impact of assets sold and assets held for sale. 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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Exploration	$14.2	$13.5	$39.3	$41.9

Exploration expense remained relatively flat for the three and nine months ended September 30, 2017, compared with the same periods in 2016. We expect our exploration expense to be lower for the full-year 2017 as compared to the full-year 2016. However, exploration expense may also vary by quarter depending upon exploratory dry hole expense.

Impairment of proved properties and abandonment and impairment of unproved properties

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Impairment of proved properties	$—	$8.0	$3.8	$277.8
Abandonment and impairment of unproved properties	$—	$3.6	$0.2	$5.9

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For the nine months ended September 30, 2016, we impaired proved properties early in the year, primarily in our outside-operated Eagle Ford shale program, as a result of continued commodity price declines, and we allowed certain leases to expire. We expect proved property impairments to occur more often in periods of declining or depressed 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. Additionally, changes in drilling plans, downward engineering revisions, or unsuccessful exploration efforts may result in proved and unproved property impairments. Any amount of future impairment is difficult to predict, but based on updated commodity price assumptions as of October 26, 2017, we do not expect any material impairments in the fourth quarter of 2017.

General and administrative

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
General and administrative	$27.9	$32.7	$85.6	$93.1

G&A expense decreased 15 percent and eight percent for the three and nine months ended September 30, 2017, compared with the same periods in 2016 primarily due to lower compensation expense resulting from decreased headcount. 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 an absolute and per BOE basis.

Net derivative (gain) loss

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Net derivative (gain) loss	$80.6	$(28.0)	$(89.4)	$121.1

We recognized an $80.6 million derivative loss for the three months ended September 30, 2017, due largely to a $72.6 million decrease in the fair value of contracts settling subsequent to September 30, 2017. Additionally, we recognized an $8.0 million loss on contracts that settled during the third quarter of 2017, which had a fair value of $21.1 million at June 30, 2017, and settled for $13.1 million. We recognized a $24.6 million gain on contract settlements through the second quarter of 2017 and recorded a $145.4 million increase in the fair value of remaining contracts as of June 30, 2017, resulting in a year-to-date net derivative gain of $89.4 million.

We recognized a $28.0 million derivative gain for the three months ended September 30, 2016, due to a $15.9 million gain on contracts that settled during the third quarter of 2016, which had a fair value of $41.6 million at June 30, 2016, and settled for $57.5 million. Additionally, during the third quarter of 2016, we recorded a $12.1 million increase in fair value of contracts settling subsequent to September 30, 2016. We recognized a $121.1 million derivative loss for the nine months ended September 30, 2016, driven largely by a $117.0 million mark-to-market loss on remaining contracts as of September 30, 2016, resulting from the increase in commodity strip prices in the second half of 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.

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

Gain (loss) on extinguishment of debt

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Gain (loss) on extinguishment of debt	$ —	$ —	$ —	$ 15.7

For the nine months ended September 30, 2016, we recorded a $15.7 million net gain on the early extinguishment of a portion of our Senior Notes during the first quarter of 2016, which included approximately $16.4 million associated with the discount realized upon repurchase, slightly offset by approximately $0.7 million 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.

Interest expense

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Interest expense	$(44.1)	$(47.2)	$(135.6)	$(112.3)

The seven percent decrease in interest expense for three months ended September 30, 2017, compared with the same period in 2016 is due primarily to $10.0 million paid during the third quarter of 2016 to terminate a second lien facility that was no longer necessary to fund the Rock Oil Acquisition. The 21 percent increase in interest expense for the nine months ended September 30, 2017, compared with the same period in 2016, was primarily due to the additional debt issued in 2016 which also resulted in an increase in our weighted-average interest rate. Please refer to Note 5 - Long-Term Debt in Part I, Item I of this report and Overview of Liquidity and Capital Resources below for additional information.

Income tax benefit

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions, except tax rate)			
Income tax benefit	$39.3	$23.7	$65.8	$314.5
Effective tax rate	30.6 %	36.7 %	32.8 %	36.1 %

The decrease in the effective tax rate for the three and nine months ended September 30, 2017, compared with the same periods in 2016, was primarily the result of recording a discrete expense in the third quarter of 2017 relating to an adjustment to record an excess tax deficiency from the settlement of share-based payment awards. This reduction of the tax benefit was partially offset by state apportionment changes due to divesting our outside-operated Eagle Ford shale assets and a decrease in valuation allowances due to projected utilization of various state net operating losses based upon our decision in the third quarter of 2017 that recognition was appropriate. This compares with an increase in valuation allowances in 2016 correlating from various projected state net operating losses, which decreased the 2016 effective tax rate. 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 and our current liquidity, we believe we have sufficient liquidity and capital resources to execute our business plan for the foreseeable future. We expect to manage the duration and level of our drilling and completion service commitments to maintain the flexibility to adjust our activity and capital expenditures during periods of prolonged weak commodity prices or to respond should commodity prices recover further.

Sources of Cash

We currently expect our 2017 capital program to be funded by cash flows from operations and proceeds from the divestiture of our outside-operated Eagle Ford shale assets during the first quarter of 2017. As of September 30, 2017, our cash balance totaled $441.4 million, which combined with our $924.8 million of available borrowing capacity under our Credit Agreement, resulted in $1.4 billion in liquidity.

Although we anticipate cash flows from operations and divestiture proceeds will be sufficient to fund our expected 2017 capital program, we may also elect to borrow under our Credit Agreement and/or raise funds through debt or equity financings or from other sources. Further, we may enter into additional carrying cost funding and sharing arrangements with third parties for particular exploration and/or development programs. See Credit Agreement below for discussion of the reduction in our borrowing base in early 2017. Our borrowing base could be further reduced as a result of lower commodity prices, divestitures of proved properties, or newly issued debt. If we raise additional funds through the issuance of equity or convertible debt securities, the percentage ownership of our current stockholders could be diluted, and these newly-issued securities may have rights, preferences, or privileges senior to those of existing stockholders. Any future downgrades in our credit ratings could 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.

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. 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, domestic production activities, percentage depletion, and other deductions that reduce our taxable income, continue to be discussed by Congress. Although we believe this possibility has decreased with the recent congressional discussions on tax reform, should future legislation eliminate these deductions we would expect a reduction in 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, reductions in available deductions could have a significant adverse effect on drilling in the United States for a number of years.

Credit Agreement

Our Credit Agreement provides for a maximum loan amount of $2.5 billion and has a maturity date of December 10, 2019. On March 31, 2017, we entered into a Ninth Amendment to the Credit Agreement. Pursuant to the Ninth Amendment, and as part of the regular, semi-annual borrowing base redetermination process, the borrowing base and aggregate lender commitments were reduced to $925 million. This expected decrease was primarily due to the sale of our outside-operated Eagle Ford shale assets in the first quarter of 2017 and the decrease in the value of our proved reserves at December 31, 2016. Additionally, as part of the Ninth Amendment, we are now able to enter into derivative contracts for an increased percentage of projected production volumes. We had a zero balance on our credit facility as of September 30, 2017, and as of the filing of this report. As of the filing of this report, the second semi-annual redetermination for 2017 was in progress and is expected to be completed prior to year-end. 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.

We must comply with certain financial and non-financial covenants under the Credit Agreement, including covenants limiting dividend payments and requiring us to maintain certain financial ratios, as defined by the Credit Agreement. Certain financial covenants under the Credit Agreement require, as of the last day of each fiscal quarter, 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, 2017, and through the filing of this report. Please refer to the caption Non-GAAP Financial Measures below for the calculation of adjusted EBITDAX and reconciliations of net loss and net cash provided by operating activities to adjusted EBITDAX.

We had minimal credit facility activity during the three and nine months ended September 30, 2017, due to our significant cash balance resulting from the divestiture of our Raven/Bear Den assets in December 2016 and proceeds received from the sale of our outside-operated Eagle Ford shale assets during the first quarter of 2017. 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. 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, the non-cash amortization of deferred financing costs, and the non-cash amortization of the discount related to the Senior Convertible Notes. 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, 2017, and 2016:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
Weighted-average interest rate	6.3%	6.2%	6.5%	6.1%
Weighted-average borrowing rate	5.7%	5.7%	5.8%	5.6%

The weighted-average interest rate and weighted-average borrowing rate remained flat for the three months ended September 30, 2017, compared with the same period in 2016, and increased for the nine months ended September 30, 2017, compared with the same period in 2016, largely due to the issuance of the Senior Convertible Notes and 2026 Notes in the third quarter of 2016. Further impacting these rates is the timing and amount of Senior Notes redemptions, changes in our aggregate lender commitment amount on our credit facility, and the average balance on our credit facility. The rates disclosed in the above table do not reflect amounts associated with the repurchase of Senior Notes, such as the discount realized or premium paid upon repurchase, or the acceleration of unamortized deferred financing costs expensed upon repurchase. The rates also do not reflect the 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.

Uses of Cash

We use cash for the acquisition, exploration, and development of oil and gas properties and for the payment of operating and general and administrative 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. During the nine months ended September 30, 2017, we spent $712.4 million on capital expenditures and on acquiring proved and unproved oil and gas properties. This amount differs from the costs incurred amount, which is accrual-based and includes asset retirement obligations, geological and geophysical expenses, and exploration overhead amounts.

The amount and allocation of our 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 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, compliance with securities laws, and other factors. The amounts involved in any such transaction may be material. Please refer to Note 5 - Long-Term Debt in Part I, Item 1 of this report for additional discussion of previously repurchased Senior Notes.

As of the filing 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 and 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 of common stock during 2017.

Analysis of Cash Flow Changes Between the Nine Months Ended September 30, 2017, and 2016

The following tables present changes in cash flows between the nine months ended September 30, 2017, and 2016, 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, 2017	2016	Amount Change Between Periods	Percent Change Between Periods
	(in millions)			
Net cash provided by operating activities	$370.6	$415.0	$(44.4)	(11)%

Cash received from oil, gas, and NGL production revenues, net of transportation costs and production taxes, including derivative cash settlements, decreased $101.8 million for the nine months ended September 30, 2017, compared with the same period in 2016, as a result of the decline in production volumes. Interest paid increased $36.3 million for the nine months ended September 30, 2017, compared with the same period in 2016, due to the issuance of our 2026 Notes and Senior Convertible Notes in the third quarter of 2016. These were partially offset by a $15.8 million decrease in cash paid for LOE, including ad valorem tax expense for the nine months ended September 30, 2017, compared with the same period in 2016. Further, net cash provided by operating activities is affected by working capital changes and the timing of cash receipts and disbursements. 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.

Investing activities

	For the Nine Months Ended September 30, 2017	2016	Amount Change Between Periods	Percent Change Between Periods
	(in millions)			
Net cash provided by (used in) investing activities	$69.0	$(361.8)	$ 430.8	119 %

The increase in cash flow from investing activities for the nine months ended September 30, 2017, compared with the same period in 2016 is largely due to increased divestiture cash proceeds of $576.5 million received. During the first nine months of 2017, these proceeds were primarily from the sale of our outside-operated Eagle Ford shale assets and during the same period of 2016, the proceeds were primarily related to the divestiture of certain Permian and Rocky Mountain assets. Proceeds received from divestitures were partially offset by a $132.2 million increase in capital expenditures, and a $65.5 million increase in proved and unproved property acquisitions in the Midland Basin during the first nine months of 2017 compared with the same period in 2016. Additionally, we made a $49.0 million deposit on the Rock Oil Acquisition during the third quarter of 2016.

Financing activities

	For the Nine Months Ended September 30, 2017	2016	Amount Change Between Periods	Percent Change Between Periods
	(in millions)			
Net cash provided by (used in) financing activities	$(7.6)	$927.5	$(935.1)	(101)%

We had a zero balance on our credit facility as of December 31, 2016, and September 30, 2017, due to our significant cash balance resulting from the proceeds received from the sale of our Raven/Bear Den assets in December 2016 and proceeds received from the sale of our outside-operated Eagle Ford shale assets and other assets during the first nine months of 2017. This compares to net repayments of $202.0 million during the nine months ended September 30, 2016. For the nine months ended September 30, 2016, we received $530.9 million net proceeds from our underwritten public equity offering of approximately 18.4 million shares of our common stock at an offering price of $30.00 per share, $166.7 million net proceeds from our Senior Convertible Notes issuance, and $492.4 million net proceeds from our 2026 Notes issuance. We used a portion of the net cash proceeds from these transactions to pay down our credit facility balance as of September 30, 2016 and used the remaining proceeds to partially fund the Rock Oil Acquisition that closed October 4, 2016. Please refer to Note 5 - Long-Term Debt and Note 15 - Equity in the Company's 2016 Form 10-K for more information on the funding for these acquisitions. Additionally, during the nine months ended September 30, 2016, we paid $29.9 million for the repurchase of a portion of our Senior Notes and we paid $24.1 million for capped call transactions related to our Senior Convertible Notes issuance. 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 associated with any outstanding balance on our revolving credit facility. As of September 30, 2017, and through the filing of this report, we had a zero balance on our 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. 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, 2017, our outstanding fixed-rate debt totaled $3.0 billion. Please refer to Note 11 - Fair Value Measurements in Part I, Item 1 of this report for additional discussion on the fair values 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 several 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. Based on our production for the nine months ended September 30, 2017, 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 $45.1 million, $28.9 million, and $17.3 million, respectively. If commodity prices had been 10 percent lower, our derivative settlements would have been higher, partially offsetting the decrease in production revenues as discussed in the next paragraph.

We enter into commodity derivative contracts in order to reduce the impact of fluctuations in commodity prices. The fair value of our commodity derivative contracts are largely determined by estimates of the forward curves of the relevant price indices. For the nine months ended September 30, 2017, a 10 percent decrease in the contract settlement prices would have increased our oil, gas, and NGL derivative settlement gain by approximately $24.2 million, $24.6 million, and $14.4 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 2017.

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 2016 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 pronouncements.

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Non-GAAP Financial Measures

Adjusted EBITDAX represents net income (loss) before interest expense, other non-operating income and expense, income taxes, depletion, depreciation, amortization and asset retirement obligation liability accretion expense, exploration expense, property abandonment and impairment expense, non-cash stock-based compensation expense, derivative gains and losses net of settlements, gains and losses on divestitures, gains and losses on extinguishment of debt, and certain other items. 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 Credit Agreement in Overview of Liquidity and Capital Resources above. 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 other 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 failed to comply with the covenants that establish a maximum permitted ratio of senior secured debt to adjusted EBITDAX and a minimum permitted ratio of adjusted EBITDAX to interest, we would 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 are in 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 default.

The following table provides reconciliations of our net 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,	
	2017	2016	2017	2016
	(in thousands)			
Net loss (GAAP)	$(89,112)	$(40,907)	$(134,585)	$(556,798)
Interest expense	44,091	47,206	135,639	112,329
Other non-operating income, net	(1,301)	(221)	(2,901)	(232)
Income tax benefit	(39,270)	(23,732)	(65,825)	(314,505)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	134,599	193,966	425,643	619,193
Exploration [1]	12,748	11,892	35,395	36,905
Impairment of proved properties	—	8,049	3,806	277,834
Abandonment and impairment of unproved properties	—	3,568	157	5,917
Stock-based compensation expense	6,347	6,570	16,160	20,485
Net derivative (gain) loss	80,599	(28,037)	(89,364)	121,086
Derivative settlement gain	13,092	57,496	29,402	306,234
Net (gain) loss on divestiture activity	1,895	(22,388)	131,565	(3,413)
(Gain) loss on extinguishment of debt	—	—	35	(15,722)
Other	785	(8,314)	5,620	(4,757)
Adjusted EBITDAX (Non-GAAP)	164,473	205,148	490,747	604,556
Interest expense	(44,091)	(47,206)	(135,639)	(112,329)
Other non-operating income, net	1,301	221	2,901	232
Income tax benefit	39,270	23,732	65,825	314,505
Exploration [1]	(12,748)	(11,892)	(35,395)	(36,905)
Amortization of debt discount and deferred financing costs	3,799	3,757	12,478	5,687
Deferred income taxes	(36,668)	(23,756)	(67,458)	(314,770)
Plugging and abandonment	(486)	(2,506)	(2,095)	(5,222)
Other, net	1,661	(3,060)	(920)	(4,100)
Changes in current assets and liabilities	11,971	13,701	40,153	(36,642)
Net cash provided by operating activities (GAAP)	$128,482	$158,139	$370,597	$415,012

[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.

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 2016 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;
- 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;
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