ABRAXAS PETROLEUM CORP
Form 10-Q
May 10, 2017

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

FORM 10-Q
(Mark One)

ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE QUARTERLY PERIOD ENDED March 31, 2017

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: 001-16071

ABRAXAS PETROLEUM CORPORATION
(Exact name of registrant as specified in its charter)

Nevada	74-2584033
(State of Incorporation)	(I.R.S. Employer Identification No.)

18803 Meisner Drive, San Antonio, TX 78258
(Address of principal executive offices) (Zip Code)

210-490-4788
(Registrant's telephone number, including area code)

Not Applicable
(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to the filing requirements for the past 90 days. Yes No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definition of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check One)

Large accelerated filer	Accelerated filer
Non-accelerated filer (Do not mark if a smaller reporting company)	Smaller reporting company
	Emerging growth company

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 Sec 13(a) of
the Exchange Act.

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

The number of shares of the issuer's common stock outstanding as of May 5, 2017 was 163,850,651.

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Forward-Looking Information

We make forward-looking statements throughout this report. Whenever you read a statement that is not simply a statement of historical fact (such as statements including words like “believe,” “expect,” “anticipate,” “intend,” “will,” “plan,” “may,” “estimate,” “could,” “potentially” or similar expressions), you must remember that these are forward-looking statements, and that our expectations may not be correct, even though we believe they are reasonable. The forward-looking information contained in this report is generally located in the material set forth under the headings “Management’s Discussion and Analysis of Financial Condition and Results of Operations” but may be found in other locations as well. These forward-looking statements generally relate to our plans and objectives for future operations and are based upon our management’s reasonable estimates of future results or trends. The factors that may affect our expectations regarding our operations include, among others, the following:

- the prices we receive for our production and the effectiveness of our hedging activities;
- the availability of capital including under our credit facility;
- our success in development, exploitation and exploration activities;
- declines in our production of oil and gas;
- our indebtedness and the significant amount of cash required to service our indebtedness;
- limits on our growth and our ability to finance our operations, fund our capital needs and respond to changing conditions imposed by our bank credit facility and restrictive debt covenants;
- our ability to make planned capital expenditures;
- ceiling test write-downs resulting, and that could result in the future, from lower oil and natural gas prices;
- political and economic conditions in oil producing countries, especially those in the Middle East;
- price and availability of alternative fuels;
- our ability to procure services and equipment for our drilling and completion activities;
- our acquisition and divestiture activities;
- weather conditions and events;
- the proximity, capacity, cost and availability of pipelines and other transportation facilities; and
- other factors discussed elsewhere in this report.

Initial production, or IP, rates, for both our wells and for those wells that are located near our properties, are limited data points in each well’s productive history. These rates are sometimes actual rates and sometimes extrapolated or normalized rates. As such, the rates for a particular well may change as additional data becomes available. Peak production rates are not necessarily indicative or predictive of future production rates, expected ultimate recovery, or EUR, or economic rates of return from such wells and should not be relied upon for such purpose. Equally, the way we calculate and report peak IP rates and the methodologies employed by others may not be consistent, and thus the values reported may not be directly and meaningfully comparable. Lateral lengths described are indicative only. Actual completed lateral lengths depend on various considerations such as lease-line offsets. Abraxas' standard length laterals, sometimes referred to as 5,000 foot laterals, are laterals with completed length generally between 4,000 feet and 5,500 feet. Mid-length laterals, sometimes referred to as 7,500 foot laterals, are laterals with completed length generally between 6,500 feet and 8,000 feet. Long laterals, sometimes referred to as 10,000 foot laterals, are laterals with completed length generally longer than 8,000 feet.

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GLOSSARY OF TERMS

Unless otherwise indicated in this report, gas volumes are stated at the legal pressure base of the State or area in which the reserves are located at 60 degrees Fahrenheit. Oil and gas equivalents are determined using the ratio of six Mcf of gas to one barrel of oil, condensate or natural gas liquids.

The following definitions shall apply to the technical terms used in this report.

Terms used to describe quantities of oil and gas:

"Bbl" – barrel or barrels.

"Bcf" – billion cubic feet of gas.

"Bcfe" – billion cubic feet of gas equivalent.

"Boe" – barrels of oil equivalent.

"Boed" – barrels of oil equivalent per day.

"MBbl" – thousand barrels.

"MBoe" – thousand barrels of oil equivalent.

"Mcf" – thousand cubic feet of gas.

"Mcfe" – thousand cubic feet of gas equivalent.

"MMBbl" – million barrels.

"MMBoe" – million barrels of oil equivalent.

"MMBtu" – million British Thermal Units of gas.

"MMcf" – million cubic feet of gas.

"MMcfe" – million cubic feet of gas equivalent.

"NGL" – natural gas liquids measured in barrels.

Terms used to describe our interests in wells and acreage:

"Developed acreage" means acreage which consists of leased acres spaced or assignable to productive wells.

"Development well" is a well drilled within the proved area of an oil or gas reservoir to the depth or stratigraphic horizon (rock layer or formation) noted to be productive for the purpose of extracting reserves.

"Dry hole" is an exploratory or development well found to be incapable of producing either oil or gas in sufficient quantities to justify completion.

"Exploratory well" is a well drilled to find and produce oil and or gas in an unproved area, to find a new reservoir in a field previously found to be producing in another reservoir, or to extend a known reservoir.

"Gross acres" are the number of acres in which we own a working interest.

"Gross well" is a well in which we own a working interest.

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“Net acres” are the sum of fractional ownership working interests in gross acres (e.g., a 50% working interest in a lease covering 320 gross acres is equivalent to 160 net acres).

“Net well” is the sum of fractional ownership working interests in gross wells.

“Productive well” is an exploratory or a development well that is not a dry hole.

“Undeveloped acreage” means those leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and gas, regardless of whether or not such acreage contains proved reserves.

Terms used to assign a present value to or to classify our reserves:

“Developed oil and gas reserves*” Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

“Proved developed non-producing reserves*” are those quantities of oil and gas reserves that are developed behind pipe in an existing well bore, from a shut-in well bore or that can be recovered through improved recovery only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells that were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells that will require additional completion work or future recompletion prior to the start of production.

“Proved developed reserves*” Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

“Proved reserves*” Reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

“Proved undeveloped reserves” or “PUDs*” Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells, in each case where a relatively major expenditure is required.

“PV-10” means estimated future net revenue, discounted at a rate of 10% per annum, before income taxes and with no price or cost escalation or de-escalation, calculated in accordance with guidelines promulgated by the Securities and Exchange Commission (“SEC”).

“Standardized Measure” means estimated future net revenue, discounted at a rate of 10% per annum, after income taxes and with no price or cost escalation or de-escalation, calculated in accordance with Accounting Standards Codification (“ASC”) 932, “Disclosures About Oil and Gas Producing Activities.”

“Undeveloped oil and gas reserves*" Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

* This definition is an abbreviated version of the complete definition set forth in Rule 4-10(a) of Regulation S-X. For the complete definition, see:
http://www.ecfr.gov/cgi-bin/retrieveECFR?gp=1&SID=7aa25d3cede06103c0ecec861362497d&ty=HTML&h=L&n=pt17.3.21

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Part I
FINANCIAL STATEMENTS

Item 1. Financial Statements

ABRAXAS PETROLEUM CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(in thousands)

	March 31, 2017 (Unaudited)	December 31, 2016
Assets		
Current assets:		
Cash and cash equivalents	$ 1,061	$—
Accounts receivable:		
Joint owners, net	992	677
Oil and gas production sales	8,316	11,595
Other	—	1,252
	9,308	13,524
Derivative asset	2,320	54
Assets held for sale	—	9,685
Other current assets	597	676
Total current assets	13,286	23,939
Property and equipment:		
Oil and gas properties, full cost method of accounting:		
Proved	804,863	794,634
Other property and equipment	38,747	38,569
Total	843,610	833,203
Less accumulated depreciation, depletion, amortization and impairment	(702,653)	(696,892)
Total property and equipment, net	140,957	136,311
Deferred financing fees, net	691	818
Derivative asset	1,342	—
Other assets	340	580
Total assets	$ 156,616	$ 161,648

See accompanying notes to condensed consolidated financial statements (unaudited).

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ABRAXAS PETROLEUM CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS (CONTINUED)
(in thousands, except share and per share data)

	March 31, 2017 (Unaudited)	December 31, 2016
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$ 16,169	$ 18,397
Joint interest oil and gas production payable	8,040	8,937
Accrued interest	9	44
Other accrued expenses	687	571
Derivative liability	495	2,382
Current maturities of long-term debt	253	786
Total current liabilities	25,653	31,117
Long-term debt – less current maturities	21,551	96,616
Other liabilities	157	157
Derivative liability long-term	2,319	6,630
Future site restoration	8,748	8,623
Total liabilities	58,428	143,143
Commitments and contingencies (Note 7)		
Stockholders’ Equity:		
Preferred stock, par value $0.01 per share – authorized 1,000,000 shares; -0- shares issued and outstanding	—	—
Common stock, par value $0.01 per share, authorized 200,000,000 shares; 163,846,651 and 135,094,017 issued and outstanding, respectively	1,638	1,351
Additional paid-in capital	409,688	343,982
Accumulated deficit	(313,138)	(326,828)
Total stockholders’ equity	98,188	18,505
Total liabilities and stockholders’ equity	$ 156,616	$ 161,648

See accompanying notes to condensed consolidated financial statements (unaudited).

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ABRAXAS PETROLEUM CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)
(in thousands except per share data)

	Three Months Ended March 31,	
	2017	2016
Revenues:		
Oil and gas production revenues	$18,787	$9,541
Other	15	23
	18,802	9,564
Operating costs and expenses:		
Lease operating	4,118	4,751
Production taxes	1,620	1,175
Rig expense	—	79
Depreciation, depletion, and amortization	5,374	5,892
Proved property impairment	—	35,085
General and administrative (including stock-based compensation of $770 and $807, respectively)	2,737	2,725
	13,849	49,707
Operating income (loss)	4,953	(40,143)
Other (income) expense:		
Interest expense	507	1,238
Amortization of deferred financing fees	137	164
(Gain) on derivative contracts	(9,381)	(665)
	(8,737)	737
Income (loss) before income tax	13,690	(40,880)
Income tax (expense) benefit	—	—
Net income (loss)	$13,690	$(40,880)
Net income (loss) per common share - basic	$0.09	$(0.39)
Net income (loss) per common share - diluted	$0.09	$(0.39)
Weighted average shares outstanding:		
Basic	154,118	104,709
Diluted	156,813	104,709

See accompanying notes to condensed consolidated financial statements (unaudited).

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ABRAXAS PETROLEM CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)
(in thousands)

	Three Months Ended March 31, 2017	2016
Operating Activities		
Net income (loss)	$13,690	$(40,880)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Net (gain) on derivative contracts	(9,381)	(665)
Derivative contract settlements	(621)	5,307
Monetization of derivative contracts	—	4,360
Depreciation, depletion, and amortization	5,374	5,892
Proved property impairment	—	35,085
Amortization of deferred financing fees	137	164
Accretion of future site restoration	112	135
Stock-based compensation	770	807
Non-cash director compensation	—	40
Changes in operating assets and liabilities:		
Accounts receivable	4,216	3,059
Other assets	515	(227)
Accounts payable and accrued expenses	(3,031)	(15,567)
Net cash provided by (used in) operating activities	11,781	(2,490)
Investing Activities		
Capital expenditures, including purchases and development of properties	(10,957)	(1,587)
Proceeds from the sale of oil and gas properties	10,622	1,597
Net cash (used in) provided by investing activities	(335)	10
Financing Activities		
Proceeds from long-term borrowings	6,000	4,000
Payments on long-term borrowings	(81,598)	(4,578)
Proceeds from issuance of common stock	65,223	—
Deferred financing fees	(10)	1
Net cash used in financing activities	(10,385)	(577)
Increase (decrease) in cash and cash equivalents	1,061	(3,057)
Cash and cash equivalents at beginning of period	—	3,540
Cash and cash equivalents at end of period	$1,061	$483
Supplemental disclosures of cash flow information:		
Interest paid	$507	$1,110

See accompanying notes to condensed consolidated financial statements (unaudited).

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ABRAXAS PETROLEUM CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
(tabular amounts in thousands, except per share data)

1. Basis of Presentation

The accounting policies followed by Abraxas Petroleum Corporation and its subsidiaries (the “Company”) are set forth in the notes to the Company’s audited consolidated financial statements in the Annual Report on Form 10-K for the year ended December 31, 2016 filed with the SEC on March 16, 2017. Such policies have been continued without change. Also, refer to the notes to those financial statements for additional details of the Company’s financial condition, results of operations, and cash flows. All material items included in those notes have not changed except as a result of normal transactions in the interim, or as disclosed within this report. The accompanying interim condensed consolidated financial statements have not been audited by our independent registered public accountants, and in the opinion of management, reflect all adjustments necessary for a fair presentation of the financial position and results of operations. Any and all adjustments are of a normal and recurring nature. Although management believes the unaudited interim related disclosures in these condensed consolidated financial statements are adequate to make the information presented not misleading, certain information and footnote disclosures normally included in annual audited consolidated financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been condensed or omitted pursuant to the rules and regulations of the SEC. The results of operations and the cash flows for the period ended March 31, 2017 are not necessarily indicative of the results to be expected for the full year. The condensed consolidated financial statements included herein should be read in conjunction with the consolidated audited financial statements and the notes thereto included in the Company’s Annual Report on Form 10-K for the year ended December 31, 2016.

Consolidation Principles

The terms “Abraxas,” “Abraxas Petroleum,” “we,” “us,” “our” or the “Company” refer to Abraxas Petroleum Corporation and of its subsidiaries, including Raven Drilling, LLC (“Raven Drilling”).

Rig Accounting

In accordance with SEC Regulation S-X, no income is to be recognized in connection with contractual drilling services performed in connection with properties in which the Company or its affiliates hold an ownership, or other economic interest. Any income not recognized as a result of this limitation is to be credited to the full cost pool and recognized through lower amortization as reserves are produced.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Recently Adopted and New Accounting Standards and Disclosures

In January 2017, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business, which changes the definition of a business to assist entities with evaluating when a set of transferred assets and activities is deemed to be a business.

Determining whether a transferred set constitutes a business is important because the accounting for a business combination differs from that of an asset acquisition. The definition of a business also affects the accounting for dispositions. Under the new standard, when substantially all of the fair value of assets acquired is concentrated in a single asset, or a group of similar assets, the assets acquired would not represent a business and business combination accounting would not be required. The new standard may result in more transactions being accounted for as asset acquisitions rather than business combinations. The standard is effective for interim and annual periods beginning after December 15, 2017 and shall be applied prospectively. It is not anticipated that adoption of this standard will have a material impact on the Company's condensed consolidated financial statements.

In August 2016, the FASB issued amended guidance to address diversity in how certain cash receipts and cash payments are presented and classified in the statement of cash flows. The amendments provide guidance on the following eight specific cash flow issues: Debt prepayment or debt extinguishment costs; settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing; contingent

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consideration payments made after a business combination; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies; distributions received from equity method investees; beneficial interests in securitization transactions; and separately identifiable cash flows and application of the predominance principle. It is not anticipated that adoption of this standard will have a material impact on the Company's condensed consolidated financial statements.

In February 2016, the FASB issued ASU 2016-02 “Leases," which supersedes ASC 840 “Leases” and creates a new topic, ASC 842 "Leases." This update requires lessees to recognize a lease liability and a lease asset for all leases, including operating leases, with a term greater than 12 months on its balance sheet. The update also expands the required quantitative and qualitative disclosures surrounding leases. This update is effective for fiscal years beginning after December 15, 2018 and interim periods within those fiscal years, with earlier application permitted. This update will be applied using a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. We are currently evaluating the effect of this update on our consolidated financial statements and related disclosures. It is not anticipated that adoption of this standard will have a material impact on the Company's condensed consolidated financial statements.

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers. The objective of ASU 2014-09 is greater consistency and comparability across industries by using a five-step model to recognize revenue from customer contracts. ASU 2014-09 also contains some new disclosure requirements under GAAP. In August 2015, the FASB issued ASU No. 2015-14, Deferral of the Effective Date. ASU 2015-14 defers the effective date of the new revenue standard by one year, making it effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. In 2016, the FASB issued additional accounting standards updates to clarify the implementation guidance of ASU 2014-09. Through March 2017, the Company made progress in identifying contracts for review and evaluating the new disclosure requirements. The Company expects to complete its evaluations of the impacts of the accounting and disclosure requirements on its business processes, controls and systems in the second half of 2017, and will continue to evaluate guidance from accounting regulatory agencies as it becomes available.

Stock-Based Compensation and Option Plans

Stock Options

The Company currently utilizes a standard option-pricing model (i.e., Black-Scholes) to measure the fair value of stock options granted to employees and directors.

The following table summarizes the Company’s stock-based compensation expense related to stock options for the periods presented:

Three Months Ended March 31,	
2017	2016
$434	$457

The following table summarizes the Company’s stock option activity for the three months ended March 31, 2017 (shares in thousands):

Number of	Weighted Average Option	Weighted Average Grant

	Shares	Exercise Price Per Share	Date Fair Value Per Share
Outstanding, December 31, 2016	8,154	$ 2.39	$ 1.70
Granted	2	2.24	1.31
Exercised	(5)	0.97	0.65
Cancelled/Forfeited	—	—	—
Outstanding, March 31, 2017	8,151	$ 2.39	$ 1.71

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As of March 31, 2017, there was approximately $2.6 million of unamortized compensation expense related to outstanding stock options that will be recognized in 2017 through 2020.

Restricted Stock Awards

Restricted stock awards are awards of common stock that are subject to restrictions on transfer and to a risk of forfeiture if the awardee terminates employment with the Company prior to the lapse of the restrictions. The fair value of such stock was determined using the closing price on the grant date and compensation expense is recorded over the applicable vesting periods.

The following table summarizes the Company's restricted stock activity for the three months ended March 31, 2017:

	Number of Shares (thousands)	Weighted Average Grant Date Fair Value Per Share
Unvested, December 31, 2016	1,492	$ 3.47
Granted	—	—
Vested/Released	(2)	3.22
Forfeited	—	—
Unvested, March 31, 2017	1,490	$ 3.47

The following table summarizes the Company's stock-based compensation expense related to restricted stock for the periods presented:

Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
$336	$350

As of March 31, 2017, there was approximately $1.6 million of unamortized compensation expense relating to outstanding restricted shares that will be recognized in 2017 through 2020.

Oil and Gas Properties

The Company follows the full cost method of accounting for oil and gas properties. Under this method, all direct costs and certain indirect costs associated with acquisition of properties and successful as well as unsuccessful exploration and development activities are capitalized. Depreciation, depletion, and amortization of capitalized oil and gas properties and estimated future development costs, excluding unproved properties, are based on the unit-of-production method based on proved reserves. Net capitalized costs of oil and gas properties, less related deferred taxes, are limited by country, to the lower of unamortized cost or the cost ceiling, defined as the sum of the present value of estimated future net revenues from proved reserves based on unescalated prices discounted at 10%, plus the cost of properties not being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. Costs in excess of the present value of estimated net revenue from proved reserves discounted at 10% are charged to proved property impairment expense. No gain or loss is recognized upon sale or disposition of oil and gas properties for full cost accounting companies with proceeds accounted for as an adjustment of capitalized cost. An exception to this rule occurs when the adjustment to the full cost pool results in a significant alteration of the relationship between capitalized cost and proved reserves. The Company applies the full cost ceiling test on a quarterly basis on the date of the latest balance sheet presented. At March 31, 2016 our net capitalized costs of oil and gas properties exceeded the present value of our estimated proved reserves by approximately $35.1 million, resulting in the recognition of an impairment for the three months of $35.1 million. At March 31, 2017, our net capitalized costs of oil and gas properties did not exceed the cost ceiling of our estimated proved reserves. Impairment calculations did not consider the impact of our commodity derivative positions as generally accepted accounting principles only allow the inclusion of derivatives designated as cash flow hedges. Further write-downs in subsequent quarters are reasonably likely to occur if the trailing 12-month commodity prices fall as compared to the commodity prices used in prior quarters.

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Restoration, Removal and Environmental Liabilities

The Company is subject to extensive federal, state and local environmental laws and regulations. These laws regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefit are expensed.

Liabilities for expenditures of a non-capital nature are recorded when environmental assessments and/or remediation is probable, and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments for the liability or component is fixed or reliably determinable.

The Company accounts for future site restoration obligations based on the guidance of ASC 410 which addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. ASC 410 requires that the fair value of a liability for an asset's retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the estimated useful life of the related asset. For all periods presented, we have included estimated future costs of abandonment and dismantlement in our full cost amortization base and amortize these costs as a component of our depletion expense in the accompanying condensed consolidated financial statements.

The following table summarizes the Company’s future site restoration obligation transactions for the three months ended March 31, 2017 and the year ended December 31, 2016:

	March 31, 2017	December 31, 2016
Beginning future site restoration obligation	$8,623	$ 9,679
New wells placed on production and other	34	119
Deletions related to property disposals and plugging costs	—	(1,832)
Accretion expense	112	491
Revisions and other	(21)	166
Ending future site restoration obligation	$8,748	$ 8,623

2. Income Taxes

The Company records income taxes using the liability method. Under this method, deferred tax assets and liabilities are determined based on differences between financial reporting and tax basis of assets and liabilities and are measured using the tax rates and laws expected to be in effect when the differences are expected to reverse.

For the three months ended March 31, 2017, there was no income tax benefit due to net operating loss carryforwards and recorded a full valuation allowance against its net deferred taxes.

The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. As of March 31, 2017, the Company did not have any accrued interest or penalties related to uncertain tax positions. The tax years 2012 through 2016 remain open to examination by the tax jurisdictions to which the Company is subject.

At December 31, 2016, the Company had, subject to the limitation discussed below, $230.5 million of net operating loss carryforwards for U.S. tax purposes. The loss carryforward will expire in varying amounts through 2036, if not utilized.

Uncertainties exist as to the future utilization of the operating loss carryforwards. Therefore, the Company has established a valuation allowance of $103.7 million for deferred tax assets at December 31, 2016.

3. Long-Term Debt

The following is a description of the Company’s debt as of March 31, 2017 and December 31, 2016, respectively:

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	March 31, 2017	December 31, 2016
Senior secured credit facility	$18,000	$93,000
Rig loan agreement	—	535
Real estate lien note	3,804	3,867
	21,804	97,402
Less current maturities	(253)	(786)
	$21,551	$96,616

Credit Facility

The Company has a senior secured credit facility with Société Générale, as administrative agent and issuing lender, and certain other lenders, which we refer to as the credit facility. As of March 31, 2017, $18.0 million was outstanding under the Credit Facility.

The credit facility has a maximum commitment of $300.0 million and availability is subject to a borrowing base. At March 31, 2017, we had a borrowing base of $115.0 million. The borrowing base is determined semi-annually by the lenders based upon our reserve reports, one of which must be prepared by our independent petroleum engineers and one of which may be prepared internally. The amount of the borrowing base is calculated by the lenders based upon their valuation of our proved reserves securing the facility utilizing these reserve reports and their own internal decisions. In addition, the lenders, in their sole discretion, are able to make one additional borrowing base redetermination during any six-month period between scheduled redeterminations and we are able to request one redetermination during any six-month period between scheduled redeterminations. Outstanding borrowings in excess of the borrowing base must be repaid immediately or we must pledge additional oil and gas properties or other assets as collateral. We do not currently have any substantial unpledged assets and we may not have the financial resources to make any mandatory principal payments. In addition, a reduction of the borrowing base could also cause us to fail to be in compliance with the financial covenants described below. The borrowing base will be automatically reduced in connection with any sales of producing properties with a market value of 5% or more of our then-current borrowing base and in connection with any hedge termination which could reduce the collateral value by 5% or more. Our borrowing base can never exceed the $300.0 million maximum commitment amount. Outstanding amounts under the credit facility bear interest (a) at any time an event of default exists, at 3% per annum plus the amounts set forth below, and (b) at all other times, at the greater of (x) the reference rate announced from time to time by Société Générale, (y) the Federal Funds Rate plus 0.5%, and (z) a rate determined by Société Générale as the daily one-month LIBOR plus, in each case, (b) 0.75%-1.75%, depending on the utilization of the borrowing base, or, if we elect, LIBOR plus, in each case, 1.75%-2.75% depending on the utilization of the borrowing base. At March 31, 2017, the interest rate on the credit facility was approximately 2.73% assuming LIBOR borrowings.

Subject to earlier termination rights and events of default, the stated maturity date of the credit facility is June 30, 2018. Interest is payable quarterly on reference rate advances and not less than quarterly on LIBOR advances. We are permitted to terminate the credit facility and are able, from time to time, to permanently reduce the lenders' aggregate commitment under the credit facility in compliance with certain notice and dollar increment requirements.

Each of our subsidiaries has guaranteed our obligations under the credit facility on a senior secured basis. Obligations under the credit facility are secured by a first priority perfected security interest, subject to certain permitted encumbrances, in all of our and our subsidiary guarantors' material property and assets. The collateral is required to include properties comprising at least 90% of the PV-10 of our proven reserves. We have also granted our lenders a security interest in our headquarters building and a ranch that we own in West Texas.

Under the credit facility, we are subject to customary covenants, including certain financial covenants and reporting requirements. We are required to maintain a current ratio, as of the last day of each quarter of not less than 1.00 to 1.00 and an interest coverage ratio of not less than 2.50 to 1.00. We are also required as of the last day of each quarter to maintain a total debt to EBITDAX ratio of not more than 4.00 to 1.00. The current ratio is defined as the ratio of consolidated current assets to consolidated current liabilities. For the purposes of this calculation, current assets include the portion of the borrowing base which is undrawn but excludes any cash deposited with a counter-party to a hedging arrangement and any assets representing a valuation account arising from the application of ASC 815 and ASC 410-20 and current liabilities exclude the current portion of long-term debt and any liabilities representing a valuation account arising from the application of ASC 815 and ASC 410-20. The interest coverage ratio is defined as the ratio of consolidated EBITDAX to consolidated interest expense for the four fiscal quarters ended on the calculation date. For the purposes of this calculation, EBITDAX is defined as the sum of consolidated net income plus interest expense, oil and gas exploration expenses, income, franchise or margin taxes, depreciation, amortization, depletion and other non-cash charges including non-cash charges resulting from the application of ASC 718, ASC 815 and ASC 410-20 plus all realized

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net cash proceeds arising from the settlement or monetization of any hedge contracts plus expenses incurred in connection with the negotiation, execution, delivery and performance of the credit facility plus expenses incurred in connection with any acquisition permitted under the credit facility plus expenses incurred in connection with any offering of senior unsecured notes, subordinated debt or equity plus up to $1.0 million of extraordinary expenses in any 12-month period plus extraordinary losses minus all non-cash items of income which were included in determining consolidated net loss, including all non-cash items resulting from the application of ASC 815 and ASC 410-20. Interest expense includes total interest, letter of credit fees and other fees and expenses incurred in connection with any debt. The total debt to EBITDAX ratio is defined as the ratio of total debt to consolidated EBITDAX for the four fiscal quarters ended on the calculation date. For the purposes of this calculation, total debt is the outstanding principal amount of debt, excluding debt associated with the headquarters building and obligations with respect to surety bonds and derivative contracts.

At March 31, 2017, we were in compliance with all of our debt covenants. As of March 31, 2017, the interest coverage ratio was 14.08 to 1.00, the total debt to EBITDAX ratio was 0.42 to 1.00, and our current ratio was 4.34 to 1.00.

The credit facility contains a number of covenants that, among other things, restrict our ability to:

- incur or guarantee additional indebtedness;
- transfer or sell assets;
- create liens on assets;
- engage in transactions with affiliates other than on an “arm’s length” basis;
- make any change in the principal nature of our business; and
- permit a change of control.

The credit facility also contains certain additional covenants including requirements that:

- 100% of the net proceeds from any terminations of derivative contracts must be used to repay amounts outstanding under the credit facility; and

- if the sum of our cash on hand plus liquid investments exceeds $10.0 million, then the amount in excess of $10.0 million must be used to pay amounts outstanding under the credit facility.

The credit facility also contains customary events of default, including nonpayment of principal or interest, violations of covenants, cross default and cross acceleration to certain other indebtedness, bankruptcy and material judgments and liabilities. As of March 31, 2017, we were in compliance with all of the terms of our credit facility.

Real Estate Lien Note

We have a real estate lien note secured by a first lien deed of trust on the property and improvements which serves as our corporate headquarters. The note bears interest at a fixed rate of 4.25% and is payable in monthly installments of $34,354. Beginning August 20, 2018, the interest rate will adjust to the bank's then current prime rate plus 1.00% with a maximum rate of 7.25%. The maturity date of the note is July 20, 2023. As of March 31, 2017 and December 31, 2016, $3.8 million and $3.9 million, respectively, were outstanding on the note.

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4. Earnings per Share

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

	Three Months Ended March 31,	
	2017	2016
	(In thousands, except per share data)	
Numerator:		
Net income (loss)	$13,690	$(40,880)
Denominator:		
Denominator for basic earnings per share – weighted-average common shares outstanding	154,118	104,709
Effect of dilutive securities: Stock options and restricted shares	2,695	—
Denominator for diluted earnings per share – adjusted weighted-average shares and assumed exercise of options and restricted shares	156,813	104,709
Net income (loss) per common share - basic	$0.09	$(0.39)
Net income (loss) per common share - diluted	$0.09	$(0.39)

Basic earnings (loss) per share, excluding any dilutive effects of stock options and unvested restricted stock, is computed by dividing net income (loss) available to common stockholders by the weighted average number of common shares outstanding for the period. Diluted income (loss) per share is computed in a manner similar to basic; however diluted income (loss) per share reflects the assumed conversion of all potentially dilutive securities. For the three months ended March 31, 2016, 1,642 potential shares related to unvested restricted shares and options were excluded from the calculation of diluted income (loss) per share since their inclusion would have been anti-dilutive due to losses incurred in the period. There were no shares excluded for the three months ended March 31, 2017.

5. Hedging Program and Derivatives

The derivative contracts we utilize are based on index prices that may and often do differ from the actual oil and gas prices realized in our operations. Our derivative contracts do not qualify for hedge accounting; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. There are no netting agreements relating to these derivative contracts and there is no policy to offset.

The following table sets forth the summary position of our derivative contracts as of March 31, 2017:

	Oil - WTI	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)
Fixed Swaps		
2017	2,396	$54.50
2018	1,796	$47.48
2019	1,197	$54.54
Basis Swap		
2017	500	$0.65

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Contract Period	Gas Daily Volume (Mmbtu)	Floor (Put)	Ceiling (Call)
Collar Contracts			
2017	5,000	$3.00	$ 3.90

Subsequent to March 31, 2017, we entered into the following derivative contracts:

Contract Periods	Oil - WTI Daily Volume (Bbl)	Swap Price (per Bbl)
Fixed Swaps		
2017 October - December	163	$54.40
2018	164	$53.91

The following table illustrates the impact of derivative contracts on the Company's balance sheet:

Fair Value of Derivative Contracts as of March 31, 2017

	Asset Derivatives		Liability Derivatives	
Derivatives not designated as hedging instruments	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity price derivatives	Derivatives – current	$2,320	Derivatives – current	$495
Commodity price derivatives	Derivatives – long-term	1,342	Derivatives – long-term	2,319
		$3,662		$2,814

Fair Value of Derivative Contracts as of December 31, 2016

	Asset Derivatives		Liability Derivatives	
Derivatives not designated as hedging instruments	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity price derivatives	Derivatives – current	$ 54	Derivatives – current	$2,382
Commodity price derivatives	Derivatives – long-term	—	Derivatives – long-term	6,630
		$ 54		$9,012

6. Financial Instruments

Assets and liabilities measured at fair value are categorized into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

- Level 1 – inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3 - inputs to the valuation methodology are unobservable and significant to the fair value measurement.

A financial instrument’s categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Company’s assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. The Company is further required to assess the creditworthiness of the counter-party to the derivative contract. The results of the assessment of non-performance risk, based on the counter-party’s credit risk, could result in an adjustment of the carrying value of the derivative instrument. The following

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tables sets forth information about the Company's assets and liabilities measured at fair value on a recurring basis as of March 31, 2017 and December 31, 2016, and indicate the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value (in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of March 31, 2017
Assets:				
NYMEX fixed price derivative contracts	$ —	$ 3,535	$ —	$ 3,535
NYMEX collars/basis differential swaps	$ —	$ —	$ 127	$ 127
Total Assets	$ —	$ 3,535	$ 127	$ 3,662
Liabilities:				
NYMEX fixed price derivative contracts	$ —	$ 2,802	$ —	$ 2,802
NYMEX collars/basis differential swaps	—	—	12	12
Total Liabilities	$ —	$ 2,802	$ 12	$ 2,814

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2016
Assets:				
NYMEX fixed price derivative contracts	$ —	$ 35	$ —	$ 35
NYMEX collars	—	—	19	19
Total Assets	$ —	$ 35	$ 19	$ 54
Liabilities:				
NYMEX fixed price derivative contracts	$ —	$ 8,759	$ —	$ 8,759
NYMEX collars/basis differential swaps	—	—	253	253
Total Liabilities	$ —	$ 8,759	$ 253	$ 9,012

The Company's derivative contracts consisted of NYMEX-based fixed price swaps, basis differential swaps and collars as of March 31, 2017, and as of December 31, 2016. Under fixed price swaps, we receive a fixed price for our production and pay a variable market price to the contract counter-party. Under a basis differential swap, if the market price is above the fixed price we pay the counter-party, if the market price is below the fixed price, the counter-party pays us. Under a collar, we pay the counterparty if the market price is above the ceiling price (short call) and the counterparty pays us if the market price is below the floor price (long put). The NYMEX-based fixed price derivative swaps, basis swaps and collars are indexed to NYMEX futures contracts, which are actively traded, for the underlying commodity and are commonly used in the energy industry. A number of financial institutions and large energy companies act as counter-parties to these type of derivative contracts. As the fair value of NYMEX-based fixed price swaps are based on a number of inputs, including contractual volumes and prices stated in each derivative contract, current and future NYMEX commodity prices, and quantitative models that are based upon readily observable market parameters that are actively quoted and can be validated through external sources, we have characterized these derivative contracts as Level 2. In order to verify the third party valuation, we enter the various inputs into a model and compare our results to the third party for reasonableness. The fair value of the collar and basis differential swap instruments are based on inputs that are not as observable as the fixed price swaps. In addition to the actively quoted market price, variables such as time value, volatility and other unobservable inputs are used. Accordingly, these instruments have been classified as Level 3.

The following is additional information for the Company's recurring fair value measurements using significant unobservable inputs (Level 3 inputs) for the three months ended March 31, 2017.

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Unobservable inputs at January 1, 2017	$ (234)
Changes in market value	318
Settlements during the period	31
Unobservable inputs at March 31, 2017	$ 115

Nonrecurring Fair Value Measurements

The Company follows the provisions of ASC 820-10 for nonfinancial assets and liabilities measured at fair value on a nonrecurring basis. As it relates to the Company, ASC 820-10 applies to certain nonfinancial assets and liabilities as may be acquired in a business combination and thereby measured at fair value and the initial recognition of asset retirement obligations for which fair value is used.

The asset retirement obligation estimates are derived from historical costs as well as management’s expectation of future cost environments. As there is no corroborating market activity to support the assumptions used, the Company has designated these liabilities as Level 3. A reconciliation of the beginning and ending balances of the Company’s asset retirement obligation is presented in Note 1.

Other Financial Instruments

The carrying amounts of our cash, cash equivalents, restricted cash, accounts receivable, accounts payable and accrued expenses approximate fair value because of the short-term maturities and/or liquid nature of these assets and liabilities. The carrying value of our debt approximates fair value as the interest rates are market rates and this debt is considered Level 2.

7. Commitments and Contingencies

From time to time, the Company is involved in litigation relating to claims arising out of its operations in the normal course of business. At March 31, 2017, the Company was not involved in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on its financial position or results of operations.

8. Subsequent Events

Subsequent to March 31, 2017, we entered into the following derivative contracts.

	Oil - WTI	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)
Fixed Swaps		
2017 October - December	163	$54.40
2018	164	$53.91

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following is a discussion of our financial condition, results of operations, liquidity and capital resources. This discussion should be read in conjunction with our consolidated financial statements and the notes thereto, included in our Annual Report on Form 10-K for the year ended December 31, 2016 filed with the SEC on March 16, 2017, and the historical unaudited condensed consolidated financial statements and notes of the Company included elsewhere in this Quarterly Report.

Except as otherwise noted, all tabular amounts are in thousands, except per unit values.

Critical Accounting Policies

There have been no changes from the Critical Accounting Policies described in our Annual Report on Form 10-K for the year ended December 31, 2016.

General

We are an independent energy company primarily engaged in the acquisition, exploration, exploitation, development and production of oil and gas in the United States. Historically, we have grown through the acquisition and subsequent development and exploitation of producing properties, principally through the redevelopment of old fields utilizing new technologies such as modern log analysis and reservoir modeling techniques as well as 3-D seismic surveys and horizontal drilling. As a result of these activities, we believe that we have a number of development opportunities on our properties. In addition, we intend to expand upon our development activities with complementary acreage acquisitions in our core areas of operation. Success in our development and exploration activities is critical in the maintenance and growth of our current production levels and associated reserves.

Factors Affecting Our Financial Results

Our financial results depend upon many factors which significantly affect our results of operations including the following:

- commodity prices and the effectiveness of our hedging arrangements;
- the level of total sales volumes of oil and gas;
- the availability of and our ability to raise additional capital resources and provide liquidity to meet cash flow needs;
- the level of and interest rates on borrowings; and
- the level and success of exploration and development activity.

Commodity Prices and Hedging Arrangements. The results of our operations are highly dependent upon the prices received for our oil and gas production. The prices we receive for our production are dependent upon spot market prices, differentials and the effectiveness of our derivative contracts, which we sometimes refer to as hedging arrangements. Substantially all of our sales of oil and gas are made in the spot market, or pursuant to contracts based on spot market prices, and not pursuant to long-term, fixed-price contracts. Accordingly, the prices received for our oil and gas production are dependent upon numerous factors beyond our control. Significant declines in prices for oil and gas could have a material adverse effect on our financial condition, results of operations, cash flows and quantities of reserves recoverable on an economic basis.

Oil and gas prices have been volatile, and this volatility is expected to continue. As a result of the many uncertainties associated with the world political environment, worldwide supplies of oil, NGL and gas, the availability of other worldwide energy supplies and the relative competitive relationships of the various energy sources in the view of consumers, we are unable to predict what changes may occur in oil, NGL, and gas prices in the future. The market price

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of oil and condensate, NGL and gas in 2017 will impact the amount of cash generated from operating activities, which will in turn impact our financial position.

During the three months ended March 31, 2017, the NYMEX future price for oil averaged $51.78 per Bbl as compared to $33.63 per Bbl in 2016. During the three months ended March 31, 2017, the NYMEX future spot price for gas averaged $3.56 per MMBtu compared to $1.98 per MMBtu in 2016. Prices closed on March 31, 2017 at $50.60 per Bbl of oil and $3.19 per MMBtu of gas, compared to closing on March 31, 2016 at $38.34 per Bbl of oil and $1.96 per MMBtu of gas. On May 5, 2017, prices closed at $46.22 per Bbl of oil and $3.27 per MMBtu of gas. If commodity prices remain at these levels or decline further, our revenue and cash flow from operations will also likely decline. In addition, lower commodity prices could also reduce the amount of oil and gas that we can produce economically. If oil and gas prices decline, our revenues, profitability and cash flow from operations will also likely decrease which could cause us to alter our business plans, including reducing our drilling activities. Such declines have required, and in future periods could also require us to write down the carrying value of our oil and gas assets which would also cause a reduction in net income. Finally, low commodity prices will likely cause a reduction of the borrowing base under our credit facility.

The realized prices that we receive for our production differ from NYMEX futures and spot market prices, principally due to:

- basis differentials which are dependent on actual delivery location;
- adjustments for BTU content;
- quality of the hydrocarbons; and
- gathering, processing and transportation costs.

The following table sets forth our average differentials for the three months ended March 31, 2017 and 2016:

	Oil - NYMEX		Gas - NYMEX	
	2017	2016	2017	2016
Average realized price (1)	$45.96	$26.21	$2.11	$0.99
Average NYMEX price	51.78	33.63	3.56	1.98
Differential	$(5.82)	$(7.42)	$(1.45)	$(0.99)

(1) Excludes the impact of derivative activities.

At March 31, 2017, our derivative contracts consisted of NYMEX-based fixed price swaps, basis differential swaps and collars. Under fixed price swaps, we receive a fixed price for our production and pay a variable market price to the contract counter-party. Under a basis differential swap, if the market price is above the fixed price we pay the counter-party, if the market price is below the fixed price, the counter-party pays us. Under a collar contract, we pay the counterparty if the market price is above the ceiling price (short call) and the counterparty pays us if the market price is below the floor price (long put).

Our derivative contracts equate to approximately 70% of the estimated oil production from our net proved developed producing reserves (based on our reserve estimates as of December 31, 2016) through December 31, 2017, 77% in 2018 and 64% in 2019. As of March 31, 2017, we also had NYMEX-based costless collar commodity arrangements on approximately 56% of our estimated net proved developed producing gas reserves (as of December 31, 2016) through December 31, 2017 and a 500 Bopd Midland - Cushing oil price differential swap at ($0.65)/Bbl. By removing a portion of price volatility on our future oil and gas production, we believe we will mitigate, but not eliminate, the potential effects of changing commodity prices on our cash flow from operations for those periods. However, when prevailing market prices are higher than our contract prices, we will not realize increased cash flow. We have in the past and will in the future sustain losses on our derivative contracts if market prices are higher than our contract prices. Conversely, when prevailing market prices are lower than our contract prices, we will sustain gains on our commodity derivative contracts. For the three months ended March 31, 2017, we realized a gain of $9.4 million, consisting of a gain of $0.6 million on closed contracts and a gain of $8.8 million related to open contracts. For the three months ended March 31, 2016, we realized a gain of $0.7 million consisting of a gain of $5.3 million on closed contracts and a loss of $4.6 million related to open contracts. We have not designated any of these derivative contracts as hedges as prescribed by applicable accounting rules.

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The following table sets forth our derivative contracts at March 31, 2017:

	Oil - WTI	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)
Fixed Swaps		
2017	2,396	$54.50
2018	1,796	$47.48
2019	1,197	$54.54
Basis Swap		
2017	500	$0.65

Contract Period	Gas Daily Volume (Mcf)	Floor (Put)	Ceiling (Call)
Collar Contracts			
2017	5,000	$3.00	$ 3.90

At March 31, 2017, the aggregate fair market value of our commodity derivative contracts was a net asset of approximately $0.8 million.

Subsequent to March 31, 2017 we entered into the following derivative contracts:

	Oil - WTI	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)
Fixed Swaps		
2017 October - December	163	$54.40
2018	164	$53.91

Production Volumes. Our proved reserves will decline as oil and gas is produced, unless we find, acquire or develop additional properties containing proved reserves or conduct successful exploration and development activities. Based on the reserve information set forth in our reserve report as of December 31, 2016, our average annual estimated decline rate for our net proved developed producing reserves is 40%; 15%; 12%; 11% and 9% in 2018, 2019, 2020, 2021 and 2022, respectively, 9% in the following five years, and approximately 9% thereafter. These rates of decline are estimates and actual production declines could be materially higher. While we have had some success in finding, acquiring and developing additional reserves, we have not always been able to fully replace the production volumes lost from natural field declines and property sales. Our ability to acquire or find additional reserves in the future will be dependent, in part, upon the amount of available funds for acquisition, exploration and development projects.

We had capital expenditures during the three months ended March 31, 2017 of $11.0 million related to our exploration and development activities. We have a capital expenditure budget for 2017 of approximately $110.0 million. Approximately $52.5 million of the 2017 budget is allocated to developing our Permian/Delaware Basin assets including approximately $15.0 million dedicated to expanding our acreage position in the Delaware Basin. The 2017 budget also allocates approximately $42.2 million for drilling and completion of wells in our Williston Basin/Bakken/Three Forks play in North Dakota, with the remaining amount allocated to the Austin Chalk/Eagle Ford area in South Texas as well as lease acquisition and general corporate expenses. The 2017 capital expenditure budget is subject to change depending upon a number of factors, including prevailing and anticipated prices for oil and gas, the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, the availability of sufficient capital resources, the results of our exploitation efforts, and our ability to obtain permits for drilling locations.

The following table presents historical net production volumes for the three months ended March 31, 2017 and 2016:

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	Three Months Ended March 31,	
	2017	2016
Total production (MBoe)	614	538
Average daily production (Boepd)	6,822	5,916
% Oil	55 %	61 %

Availability of Capital. As described more fully under "Liquidity and Capital Resources" below, our sources of capital are cash flow from operating activities, borrowings under our credit facility, cash on hand, proceeds from the sale of properties, monetizing of derivative instruments, and if an appropriate opportunity presents itself, the sale of debt or equity securities, although we may not be able to complete any financing on terms acceptable to us, if at all. In January 2017, we completed a stock offering of 28.8 million shares of common stock for net proceeds of approximately $65.2 million. The net proceeds from this offering were used to repay borrowings under our credit facility. As of March 31, 2017, our borrowing base was $115.0 million with $97.0 million of availability under our credit facility.

Borrowings and Interest. At March 31, 2017, we had a total of $18.0 million outstanding under our credit facility and total indebtedness of $21.8 million (including the current portion). If interest expense increases as a result of higher interest rates or increased borrowings, more cash flow from operations would be used to meet debt service requirements. As a result, we would need to increase our cash flow from operations in order to fund the development of our drilling opportunities which, in turn, will be dependent upon the level of our production volumes and commodity prices.

Exploration and Development Activity. We believe that our high quality asset base, high degree of operational control and inventory of drilling projects position us for future growth. At December 31, 2016, we operated properties accounting for approximately 95% of our PV-10, giving us substantial control over the timing and incurrence of operating and capital expenditures. We have identified numerous additional drilling locations on our existing leaseholds, the successful development of which we believe could significantly increase our production and proved reserves. Over the five years ended December 31, 2016, we drilled or participated in 124 gross (46.2 net) wells of which 97% were commercially productive.

Our future oil and gas production, and therefore our success, is highly dependent upon our ability to find, acquire and develop additional reserves that are profitable to produce. The rate of production from our oil and gas properties and our proved reserves will decline as our reserves are produced unless we acquire additional properties containing proved reserves, conduct successful development and exploration activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves. We cannot assure you that our exploration and development activities will result in increases in our proved reserves. If our proved reserves decline in the future, our production may also decline and, consequently, our cash flow from operations and the amount that we are able to borrow under our credit facility may also decline. In addition, approximately 66% of our estimated proved reserves on a Boe basis (33% on a PV-10 basis) at December 31, 2016 were undeveloped. By their nature, estimates of undeveloped reserves are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling operations. We may be unable to acquire or develop additional reserves or develop our existing undeveloped reserves, in which case our results of operations and financial condition could be adversely affected.

Operational Update

Delaware Basin

In Ward County, Texas, the Caprito 98-201H and Caprito 98-301HR are drilled, cased and scheduled for a June 2017 completion. The Caprito 98-301HR targeted the Wolfcamp A2 zone and the Caprito 98-201H targeted the Wolfcamp A1 zone. We estimate that we will own a working interest of approximately 88% in the Caprito 98-201H and 98-301H.

We recently spud a two well pad in the Caprito 83-304H and Caprito 83-404H. The Caprito 83-304H is targeting the Wolfcamp A2 zone and the Caprito 83-404H is targeting the Wolfcamp B zone. We estimate that we will own a working interest of approximately 81% in the Caprito 83-304H and Caprito 83-404H.

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Williston Basin
At our North Fork prospect, in McKenzie County, North Dakota, the Stenehjem 6H-9H are drilled, cased and scheduled for completion in the coming weeks. We own a working interest of approximately 75% in the Stenehjem 6H-9H.

We recently spud a three well pad on the Company's Yellowstone unit. The Yellowstone 2H and 4H will target the Middle Bakken and the Yellowstone 3H will target the Three Forks. We own a working interest of approximately 52% in the Yellowstone 2H-4H.

Eagle Ford/Austin Chalk

In Atascosa County, Texas, we recently spud the Shut Eye 1H targeting the Eagle Ford formation. As a reminder, we will be testing the use of diverters and other enhanced completion techniques to improve the economic viability of the Eagle Ford formation at Jourdanton. Testing the Eagle Ford will have the added benefit of holding acreage through the entire lower Eagle Ford and maintaining the Austin Chalk rights. We will have a 100% working interest in the Shut Eye 1H.

2017 Outlook

Market prices for oil, gas and NGL are inherently volatile. Accordingly, we cannot predict with certainty the future prices for the commodities we produce and sell. Current market fundamentals indicate prices for oil, gas and NGL will be higher than experienced during much of 2016, although remaining much lower than prices prior to mid-2014. Lower prices for oil and gas have had and will likely continue to have a material adverse effect on our results of operations and liquidity.

Our primary sources of liquidity are cash flow from operations and borrowings under our credit facility. Cash flow from operations is sensitive to many variables, the most volatile of which is the price of the oil, gas and NGL we produce and sell. Lower prices and/or lower production will cause our cash flow from operations to decrease. Availability under our credit facility is currently subject to a borrowing base of $115.0 million. The borrowing base is subject to scheduled semiannual (April 1 and October 1) and other elective borrowing base redeterminations. The amount of the borrowing base is calculated by the lenders based upon their valuation of our proved reserves securing the facility utilizing these reserve reports and their own internal decisions. The lenders under our credit facility can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our credit facility. As a result of the decline in commodity prices for oil, gas and NGL, our borrowing base was reduced in 2016. If prices were to decline again in 2017, we would likely experience a decrease in the borrowing base.

In 2016, as a result of the sharp decline in commodity prices, we incurred impairments to our proved properties of $67.6 million. If commodity prices decrease in the future, we would likely incur additional impairments.

Results of Operations

Selected Operating Data. The following table sets forth operating data from continuing operations for the periods presented.

	Three Months Ended March 31,	
	2017	2016
Operating revenue (1):		

Oil sales	$15,502	$8,565
Gas sales	1,982	773
NGL sales	1,303	203
Other	15	23
Total operating revenues	$18,802	$9,564
Operating income (loss)	4,953	$(40,143)
Oil sales (MBbls)	337	327

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Gas sales (MMcf)	939	778
NGL sales (MBbls)	120	82
Oil equivalents (MBoe)	614	538
Average oil sales price (per Bbl)(1)	$45.96	$26.21
Average gas sales price (per Mcf)(1)	$2.11	$0.99
Average NGL sales price (per Bbl)	$10.84	$2.48
Average oil equivalent sales price (Boe) (1)	$30.60	$17.72

(1) Revenue and average sales prices are before the impact of hedging activities.

Comparison of Three Months Ended March 31, 2017 to Three Months Ended March 31, 2016

Operating Revenue. During the three months ended March 31, 2017, operating revenue increased to $18.8 million from $9.6 million for the same period of 2016. The increase in revenue was primarily due to higher prices for all products as well as higher sales volumes. Higher realized commodity prices contributed $8.7 million to operating revenue, of which $6.7 million was attributable to oil. Higher sales volumes contributed $0.5 million to operating revenue for the three months ended March 31, 2017.

Oil sales volumes increased to 337 MBbl during the three months ended March 31, 2017 from 327 MBbl for the same period of 2016. The increase in oil sales volume was primarily due to new wells brought on line since the first quarter of 2016, offset by natural field declines and property sales. New wells brought on line since the first quarter of 2016 contributed 155 MBbl for the three months ended March 31, 2017. Gas sales volumes increased to 939 MMcf for the three months ended March 31, 2017 from 778 MMcf for the same period of 2016. The increase in gas production was due to new wells brought on line since March 31, 2016 which contributed 258 MMcf for the three months ended March 31, 2017, which was partially offset by natural field declines as well as pipeline constraints. NGL sales volumes increased to 120 MBbl for the three months ended March 31, 2017 from 82 MBbl for the same period of 2016. The increase in NGL sales was primarily due to more gas production in the Rocky Mountain Region which has a higher NGL content. NGL sales were negatively impacted by plant and pipeline issues in North Dakota and West Texas.

Lease Operating Expenses (“LOE”). LOE for the three months ended March 31, 2017 decreased to $4.1 million from $4.8 million for the same period in 2016. The decrease in LOE was primarily due to lower cost of services and less non-recurring LOE in the first quarter of 2017. Additionally, we have focused on lowering LOE and shutting in marginal wells, as well as sales of non-core properties. LOE per Boe for the three months ended March 31, 2017 was $6.71 compared to $8.82 for the same period of 2016. The decrease per Boe was due to lower costs incurred and higher sales volumes for the three months ended March 31, 2017 as compared to the same period of 2016.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the three months ended March 31, 2017 increased to $1.6 million from $1.2 million for the same period of 2016. The increase was due to higher commodity prices and higher sales volumes for the three months ended March 31, 2017 as compared to the same period of 2016. Production taxes for the three months ended March 31, 2017 were 9% of total oil, gas and NGL sales compared to 12% for the same period of 2016.

General and Administrative (“G&A”) Expense. G&A expenses, excluding stock-based compensation, for the three months ended March 31, 2017 increased to $2.0 million from $1.9 million for the same period of 2016. The increase in G&A expense was primarily due to the reinstatement of officers' salaries effective February 1, 2017. G&A expense per Boe, excluding stock-based compensation, was $3.20 for the quarter ended March 31, 2017 compared to $3.56 for the same period of 2016. The decrease per Boe was primarily due to higher sales volumes partially offset by slightly higher costs.

Stock-Based Compensation. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options vesting period. In addition to options, restricted shares of the Company’s common stock have been granted and are valued at the date of grant and expense was recognized over their vesting period. For the three months ended March 31, 2017 and 2016, stock-based compensation expense was $0.8 million for each period.
Depreciation, Depletion and Amortization (“DD&A”) Expense. DD&A expense for the three months ended March 31, 2017 decreased to $5.4 million from $5.9 million for the same period of 2016. The decrease was primarily

the result of a reduction in the full cost pool as a result of the proved property impairment in 2016. DD&A expense per Boe for the three months ended March 31, 2017 was $8.75 compared to $10.94 in 2016.

Ceiling Limitation Write-Down. We record the carrying value of our oil and gas properties using the full cost method of accounting for oil and gas properties. Under this method, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under the full cost accounting rules, the net capitalized cost of oil and gas properties less related deferred taxes, are limited by country, to the lower of the unamortized cost or the cost ceiling, defined as the sum of the present value of estimated unescalated future revenues from proved reserves, discounted at 10%, plus the cost of properties not being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. If the net capitalized cost of oil and gas properties exceeds the ceiling limit, we are subject to a ceiling limitation write-down to the extent of such excess. A ceiling limitation write-down is a charge to earnings which does not impact cash flow from operating activities. However, such write-downs do impact the amount of our stockholders' equity and reported earnings. As of March 31, 2017, our net capitalized costs of oil and gas properties did not exceed the cost ceiling of our estimated proved reserves. As of March 31, 2016, our net capitalized costs of oil and gas properties exceeded the cost ceiling of our estimated proved reserves by approximately $35.1 million, resulting in the recognition of a proved property impairment of the same amount.

The risk that we will be required to write-down the carrying value of our oil and gas assets increases when oil and gas prices are depressed or volatile. In addition, write-downs may occur if we have substantial downward revisions in our estimated proved reserves. We cannot assure you that we will not experience additional write-downs in the future. If commodity prices decline or if any of our proved reserves are revised downward, a further write-down of the carrying value of our oil and gas properties may be required.

Interest Expense. Interest expense for the three months ended March 31, 2017 decreased to $0.5 million compared to $1.2 million for the same period of 2016. The decrease in interest expense was due to significantly lower levels of debt for the three months ended March 31, 2017 as compared to the same period in 2016.

Loss (Gain) on Derivative Contracts. Derivative gains or losses are determined by actual derivative settlements during the period and on the periodic mark to market valuation of derivative contracts in place. We have elected not to apply hedge accounting to our derivative contracts; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. Our derivative contracts consisted of NYMEX-based fixed price swaps, basis differential swaps and collars as of March 31, 2017, and NYMEX-based fixed price swaps and three-way collar contracts as of March 31, 2016. The estimated value of our commodity derivative contracts was a net asset of approximately $0.8 million as of March 31, 2017. When our derivative contract prices are higher than prevailing market prices, we incur gains and conversely, when our derivative contract prices are lower than prevailing market prices, we incur losses. For the three months ended March 31, 2017, we recognized a gain on our commodity derivative contracts of $9.4 million, consisting of a gain on closed contracts of $0.6 million and a gain of $8.8 million relating to open contracts. For the three months ended March 31, 2016, we recognized a gain on our commodity derivative contracts of $0.7 million, consisting of a gain of $5.3 million on closed contracts and a loss of $4.6 million related to open contracts.

Income Tax Expense. For the three months ended March 31, 2017 and 2016 there was no income tax expense recognized as a result of NOL carryforwards and a net loss in the three months ended March 31, 2016.

Liquidity and Capital Resources

General. The oil and gas industry is a highly capital intensive and cyclical business. Our capital requirements are driven principally by our obligations to service debt and to fund the following:

- the development and exploration of existing properties, including drilling and completion costs of wells;
- acquisition of interests in additional oil and gas properties; and
- production and transportation facilities.

The amount of capital expenditures we are able to make has a direct impact on our ability to increase cash flow from operations and, thereby, will directly affect our ability to service our debt obligations and to grow the business through the development of existing properties and the acquisition of new properties.

Our principal sources of capital are cash flow from operations, borrowings under our credit facility, cash on hand, proceeds from the sale of properties, monetizing of derivative contracts and if appropriate opportunities are available, the sale of debt or equity securities, although we may not be able to complete any such transactions on terms acceptable

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to us, if at all. Based upon current oil, gas and NGL price expectations and our commodity derivatives positions, we anticipate that our cash on hand, cash flow from operations and available borrowing capacity under our revolving credit facility will provide us sufficient liquidity to fund our operations for the remainder of 2017 including our planned capital expenditures.

On January 3, 2017 we closed on the sale of non-core oil and gas properties in Wyoming. Net proceeds of approximately $10.6 million were used to reduce amounts outstanding under our credit facility. In January 2017, we completed an offering of 28.8 million shares of common stock for net proceeds of approximately $65.2 million. Proceeds from the offering were used to reduce amounts outstanding under our credit facility.

Capital Expenditures. Capital expenditures for the three months ended March 31, 2017 and 2016 were $11.0 million and $1.6 million, respectively.

The table below sets forth the components of these capital expenditures:

	Three Months Ended March 31, 2017	2016
	(In thousands)	
Expenditure category:		
Exploration/Development	$10,778	$1,565
Facilities and other	179	22
Total	$10,957	$1,587

During the three months ended March 31, 2017 and 2016, our expenditures were primarily for development of our existing properties as well as the acquisition of leaseholds. We anticipate making capital expenditures in 2017 of approximately $110.0 million. Approximately $52.5 million of the 2017 budget is allocated to developing our Permian/Delaware Basin assets including approximately $15.0 million dedicated to expanding our acreage position in the Delaware Basin. The 2017 budget also allocates approximately $42.2 million for drilling and completion of wells in our Williston Basin/Bakken/Three Forks play in North Dakota, with the remaining amount allocated to the Austin Chalk/Eagle Ford area in South Texas as well as lease acquisition and general corporate expenses. The 2017 capital expenditure budget is subject to change depending upon a number of factors, including the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the availability of sufficient capital resources, our financial results and our ability to obtain permits for drilling locations. Additionally, the level of capital expenditures will vary during future periods depending on economic and industry conditions and commodity prices. Should the prices of oil and gas decline and if our costs of operations increase or if our production volumes decrease, our cash flows will decrease which may result in a reduction of the capital expenditure budget. If we decrease our capital expenditure budget, we may not be able to offset oil and gas production decreases caused by natural field declines.

Sources of Capital. The net funds provided by and/or used in each of the operating, investing and financing activities are summarized in the following table and discussed in further detail below:

	Three Months Ended March 31, 2017	2016
	(In thousands)	
Net cash provided by (used in) operating activities	$11,781	$(2,490)
Net cash (used in) provided by investing activities	(335)	10
Net cash used in financing activities	(10,385)	(577)

Total	$1,061	$(3,057)

Operating activities for the three months ended March 31, 2017 provided $11.8 million in cash compared to using $2.5 million in the same period of 2016. Non-cash expense items and net changes in operating assets and liabilities accounted for most of these funds. Investing activities used $0.3 million during the three months ended March 31, 2017, as expenditures of $11.0 million for the development of our existing properties were offset by proceeds from the sale of properties classified as assets held for sale as of December 31, 2016 of $10.6 million. Investing activities provided $0.01 million during the three months ended March 31, 2016, as proceeds from sales of oil and gas properties of $1.60 million offset expenditures of $1.59 million. Financing activities used $10.4 million for the three months ended March 31, 2017 compared to using $0.6 million for the same period of 2016. Funds used during the three months ended March 31, 2017 were primarily payments of borrowings under our credit facility, offset by proceeds from the issuance 28.8 million shares of common stock in January 2017 and borrowings under our credit facility. Funds used during the three months ended March 31, 2016 were primarily payments of our borrowings under our credit facility which were offset by proceeds from borrowings under the credit facility.

Future Capital Resources. Our principal sources of capital going forward are cash flows from operations, borrowings under our credit facility, cash on hand, proceeds from the sale of properties, monetizing derivative instruments and if an opportunity presents itself, the sale of debt or equity securities, although we may not be able to complete any financing on terms acceptable to us, if at all. In January 2017, we completed an offering of 28.8 million shares of common stock for net proceeds of approximately $65.2 million. Proceeds from the offering were used to reduce amounts outstanding under our credit facility.

Cash from operating activities is dependent upon commodity prices and production volumes. Depressed commodity prices have reduced, and further decreases in commodity prices from current levels could reduce our cash flows from operations. This could cause us to alter our business plans, including reducing our exploration and development plans. Unless we otherwise expand and develop reserves, our production volumes may decline as reserves are produced. In the future we may continue to sell producing properties, which could further reduce our production volumes. To offset the loss in production volumes resulting from natural field declines and sales of producing properties, we must conduct successful exploration and development activities, acquire additional producing properties or identify and develop additional behind-pipe zones or secondary recovery reserves. We believe our numerous drilling opportunities will allow us to increase our production volumes; however, our drilling activities are subject to numerous risks, including availability of capital and the risk that no commercially productive oil and gas reservoirs will be found. If our proved reserves decline in the future, our production could also decline and, consequently, our cash flow from operations and the amount that we are able to borrow under our credit facility could also decline. The risk of not finding commercially productive reservoirs will be compounded by the fact that 66% of our total estimated proved reserves on a Boe basis (33% on a PV-10 basis) at December 31, 2016 were classified as undeveloped.

We have in the past, and may in the future, sell producing properties. We have also sold debt and equity securities in the past, and may sell additional debt and equity securities in the future when the opportunity presents itself.

Contractual Obligations. We are committed to making cash payments in the future on the following types of agreements:

- Long-term debt, and
- Operating leases for office facilities.

Below is a schedule of the future payments that we are obligated to make based on agreements in place as of March 31, 2017:

	Payments due in twelve month periods ending:				
Contractual Obligations (In thousands)	Total	March 31, 2018	March 31, 2019-2020	March 31, 2021-2022	Thereafter
Long-term debt (1)	$21,804	$ 253	$ 18,540	$ 589	$ 2,422

Interest on long-term debt (2)	1,417	650	407	235	125
Lease obligations (3)	61	45	16	—	—
Total	$23,282	$ 948	$ 18,963	$ 824	$ 2,547

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(1) These amounts represent the balances outstanding under our credit facility and the real estate lien note. These payments assume that we will not borrow additional funds.

(2) Interest expense assumes the balances of long-term debt at the end of the period and current effective interest rates.

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(3) Lease on office space in Dickinson, North Dakota, which expires on October 31, 2018, office space in Lusk, Wyoming, which will expire on December 31, 2017 and office space in Denver, Colorado which will expire on December 31, 2017.

We maintain a reserve for costs associated with future site restoration related to the retirement of tangible long-lived assets. At March 31, 2017, our reserve for these obligations totaled $8.7 million for which no contractual commitments exist. For additional information relating to this obligation, see Note 1 of the Notes to Condensed Consolidated Financial Statements.

Off-Balance Sheet Arrangements. At March 31, 2017 we had no existing off-balance sheet arrangements, as defined under SEC regulations, that have, or are reasonably likely to have a current or future material effect on our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that are material to investors.

Contingencies. From time to time, we are involved in litigation relating to claims arising out of our operations in the normal course of business. At March 31, 2017, we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on us.

Long-Term Indebtedness.

Long-term debt consisted of the following:

	March 31, 2017	December 31, 2016
	(In thousands)	
Credit facility	$18,000	$ 93,000
Rig loan agreement	—	535
Real estate lien note	3,804	3,867
	21,804	97,402
Less current maturities	(253)	(786)
	$21,551	$ 96,616

Credit Facility

The Company has a senior secured credit facility with Société Générale, as administrative agent and issuing lender, and certain other lenders, which we refer to as the credit facility. As of March 31, 2017, $18.0 million was outstanding under the Credit Facility.

The credit facility has a maximum commitment of $300.0 million and availability is subject to a borrowing base. At March 31, 2017, we had a borrowing base of $115.0 million. The borrowing base is determined semi-annually by the lenders based upon our reserve reports, one of which must be prepared by our independent petroleum engineers and one of which may be prepared internally. The amount of the borrowing base is calculated by the lenders based upon their valuation of our proved reserves securing the facility utilizing these reserve reports and their own internal decisions. In addition, the lenders, in their sole discretion, are able to make one additional borrowing base redetermination during any six-month period between scheduled redeterminations and we are able to request one redetermination during any six-month period between scheduled redeterminations. Outstanding borrowings in excess of the borrowing base must be repaid immediately or we must pledge additional oil and gas properties or other assets as collateral. We do not currently have any substantial unpledged assets and we may not have the financial resources to make any mandatory principal payments. In addition, a reduction of the borrowing base could also cause us to fail to be in compliance with the financial covenants described below. The borrowing base will be automatically reduced in connection with any sales of producing properties with a market value of 5% or more of our then-current borrowing base and in connection with any hedge termination which could reduce the collateral value by 5% or more. Our borrowing base can never exceed the $300.0 million maximum commitment amount. Outstanding amounts under the credit facility bear interest at (a) at any time an event of default exists, at 3% per annum plus the amounts set forth below, and (b) at all other times, at the greater of (x) the reference rate announced from time to time by Société Générale, (y) the Federal Funds Rate plus 0.5%, and (z a rate determined by Société Générale as the daily one-month LIBOR plus, in each case, (i) 0.75%-1.75%, depending on the utilization of the borrowing base, or, (ii) if we elect, LIBOR plus, in each case, 1.75%-2.75% depending on the utilization of the borrowing base. At March 31, 2017, the interest rate on the credit facility was approximately 2.73% assuming LIBOR borrowings.

Subject to earlier termination rights and events of default, the stated maturity date of the credit facility is June 30, 2018. Interest is payable quarterly on reference rate advances and not less than quarterly on LIBOR advances. We are permitted to terminate the credit facility and are able, from time to time, to permanently reduce the lenders' aggregate commitment under the credit facility in compliance with certain notice and dollar increment requirements.

Each of our subsidiaries has guaranteed our obligations under the credit facility on a senior secured basis. Obligations under the credit facility are secured by a first priority perfected security interest, subject to certain permitted encumbrances, in all of our and our subsidiary guarantors' material property and assets. The collateral is required to include properties comprising of least 90% of the PV-10 of our proven reserves. We have also granted our lenders a security interest in our headquarters building and a ranch that we own in West Texas.

Under the credit facility, we are subject to customary covenants, including certain financial covenants and reporting requirements. We are required to maintain a current ratio, as of the last day of each quarter of not less than 1.00 to 1.00 and an interest coverage ratio of not less than 2.50 to 1.00. We are also required as of the last day of each quarter to maintain a total debt to EBITDAX ratio of not more than 4.00 to 1.00. The current ratio is defined as the ratio of consolidated current assets to consolidated current liabilities. For the purposes of this calculation, current assets include the portion of the borrowing base which is undrawn but excludes any cash deposited with a counter-party to a hedging arrangement and any assets representing a valuation account arising from the application of ASC 815 and ASC 410-20 and current liabilities exclude the current portion of long-term debt and any liabilities representing a valuation account arising from the application of ASC 815 and ASC 410-20. The interest coverage ratio is defined as the ratio of consolidated EBITDAX to consolidated interest expense for the four fiscal quarters ended on the calculation date. For the purposes of this calculation, EBITDAX is defined as the sum of consolidated net income plus interest expense, oil and gas exploration expenses, income, franchise or margin taxes, depreciation, amortization, depletion and other non-cash charges including non-cash charges resulting from the application of ASC 718, ASC 815 and ASC 410-20 plus all realized net cash proceeds arising from the settlement or monetization of any hedge contracts plus expenses incurred in connection with the negotiation, execution, delivery and performance of the credit facility plus expenses incurred in connection with any acquisition permitted under the credit facility plus expenses incurred in connection with any offering of senior unsecured notes, subordinated debt or equity plus up to $1.0 million of extraordinary expenses in any 12-month period plus extraordinary losses minus all non-cash items of income which were included in determining consolidated net loss, including all non-cash items resulting from the application of ASC 815 and ASC 410-20. Interest expense includes total interest, letter of credit fees and other fees and expenses incurred in connection with any debt. The total debt to EBITDAX ratio is defined as the ratio of total debt to consolidated EBITDAX for the four fiscal quarters ended on the calculation date. For the purposes of this calculation, total debt is the outstanding principal amount of debt, excluding debt associated with our headquarters building and obligations with respect to surety bonds and derivative contracts.

At March 31, 2017, we were in compliance with all of our debt covenants. As of March 31, 2017, the interest coverage ratio was 14.08 to 1.00, the total debt to EBITDAX ratio was 0.42 to 1.00, and our current ratio was 4.34 to 1.00.

The credit facility contains a number of covenants that, among other things, restrict our ability to:

- incur or guarantee additional indebtedness;
- transfer or sell assets;
- create liens on assets;
- engage in transactions with affiliates other than on an "arm's length" basis;
- make any change in the principal nature of our business; and

- permit a change of control.

The credit facility also contains certain additional covenants including requirements that:

- 100% of the net proceeds from any terminations of derivative contracts must be used to repay amounts outstanding under the credit facility; and

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- if the sum of our cash on hand plus liquid investments exceeds $10.0 million, then the amount in excess of $10.0 million must be used to pay amounts outstanding under the credit facility.

The credit facility also contains customary events of default, including nonpayment of principal or interest, violations of covenants, cross default and cross acceleration to certain other indebtedness, bankruptcy and material judgments and liabilities. As of March 31, 2017, we were in compliance with all of the terms of our credit facility.

Real Estate Lien Note

We have a real estate lien note secured by a first lien deed of trust on the property and improvements which serves as our corporate headquarters. The note bears interest at a fixed rate of 4.25% and is payable in monthly installments of $34,354. Beginning August 20, 2018, the interest rate will adjust to the bank's then current prime rate plus 1.00% with a maximum rate of 7.25%. The maturity date of the note is July 20, 2023. As of March 31, 2017 and December 31, 2016, $3.8 million and $3.9 million, respectively, were outstanding on the note.

Hedging Activities

Our results of operations are significantly affected by fluctuations in commodity prices and we seek to reduce our exposure to price volatility by hedging our production through swaps, options and other commodity derivative instruments. We have entered into commodity swaps on approximately 70% of our estimated oil production from our net proved developed producing reserves (based on reserve estimates as of December 31, 2016) through December 31, 2017, 77% for 2018 and 64% for 2019. We have also entered into a NYMEX-based collar on approximately 56% of the gas production of our estimated net proved developed producing reserves (as of December 31, 2016) through December 31, 2017 and a 500 Bopd Midland-Cushing oil price differential swap at ($0.65)/Bbl.

By removing a portion of price volatility on our future oil and gas production, we believe that we will mitigate, but not eliminate, the potential effects of changing commodity prices on our cash flow from operations. However, when prevailing market prices are higher than our contract prices, we will not realize increased cash flow on the portion of the production that has been hedged. We have sustained, and in the future will sustain, losses on our derivative contracts when market prices are higher than our contract prices. Conversely, when prevailing market prices are lower than our contract prices, we will sustain gains on our commodity derivative contracts.

If the disparity between our contract prices and market prices continues, we will sustain gains or losses on our derivative contracts. While gains and losses resulting from the periodic mark to market of our open contracts do not impact our cash flow from operations, gains and losses from settlements of our closed contracts do impact our cash flow from operations.

In addition, as our derivative contracts expire over time, we expect to enter into new derivative contracts at then-current market prices. If the prices at which we hedge future production are significantly lower than our existing derivative contracts, our future cash flow from operations would likely be materially lower.

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Item 3. Quantitative and Qualitative Disclosures about Market Risk.

Commodity Price Risk

As an independent oil and gas producer, our revenue, cash flow from operations, other income and profitability, reserve values, access to capital and future rate of growth are substantially dependent upon the prevailing prices of oil and gas. Declines in commodity prices will adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower commodity prices may reduce the amount of oil and gas that we can produce economically. Prevailing prices for such commodities are subject to wide fluctuation in response to relatively minor changes in supply and demand and a variety of additional factors beyond our control, such as global, political and economic conditions. Historically, prices received for our oil and gas production have been volatile and unpredictable, and such volatility is expected to continue. Most of our production is sold at market prices. Generally, if the commodity indexes fall, the price that we receive for our production will also decline. Therefore, the amount of revenue that we realize is partially determined by factors beyond our control. Assuming the production levels we attained during the three months ended March 31, 2017, a 10% decline in oil and gas prices would have reduced our operating revenue, cash flow and net income by approximately $1.9 million. If commodity prices remain at their current levels the impact on operating revenues and cash flow, could be much more significant. However, we do have derivative contracts in place that will mitigate the impact of low commodity prices.

Derivative Instrument Sensitivity

At March 31, 2017, the aggregate fair market value of our commodity derivative contracts was a net asset of approximately $0.8 million. The fair market value of our commodity derivative contracts is sensitive to changes in the market price for oil and gas. When our derivative contract prices are higher than prevailing market prices, we incur gains and conversely, when our derivative contract prices are lower than prevailing market prices, we incur losses. A 10% increase or decrease in commodity price futures could cause an equivalent change in fair value of our contracts and accordingly our gains and losses on the contracts.

Interest Rate Risk

We are subject to interest rate risk associated with borrowings under our credit facility. As of March 31, 2017, we had $18.0 million of outstanding indebtedness under our credit facility. Outstanding amounts under the credit facility bear interest at (a) at any time an event of default exists, at 3% per annum plus the amounts set forth below and (b) the greater of (1) the reference rate announced from time to time by Société Générale, (2) the Federal Funds Rate plus 0.5%, and (3) a rate determined by Société Générale as the daily one-month LIBOR plus, in each case, 0.75%-1.75%, depending on the utilization of the borrowing base, or, if we elect LIBOR plus 1.75%-2.75%, depending on the utilization of the borrowing base. At March 31, 2017 the interest rate on the credit facility was approximately 2.73% assuming LIBOR borrowings. For every percentage point that the LIBOR rate rises, our interest expense would increase by approximately $0.2 million on an annual basis, based on our outstanding indebtedness as of March 31, 2017.

Item 4. Controls and Procedures.

As of the end of the period covered by this report, our Chief Executive Officer and Chief Financial Officer carried out an evaluation of the effectiveness of Abraxas' "disclosure controls and procedures" (as defined in the Securities Exchange Act of 1934 Rules 13a-15(e)and 15d-15(e)) and concluded that the disclosure controls and procedures were effective.

There were no changes in our internal controls over financial reporting during the three months ended March 31, 2017 covered by this report that could materially affect, or are reasonably likely to materially affect, our financial reporting.

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PART II

Item 1. Legal Proceedings.

From time to time, the Company is involved in litigation relating to claims arising out of its operations in the normal course of business. At March 31, 2017, the Company was not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse impact on its financial position or results of operations.

Item 1A. Risk Factors.

In addition to the other information set forth in this report, you should carefully consider 4he factors discussed in Part I, "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2016, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K are not the only risks facing Abraxas. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

None

Item 3. Defaults Upon Senior Securities.

None

Item 4. Mine Safety Disclosure.

Not applicable

Item 5. Other Information.

None

Item 6. Exhibits.

(a) Exhibits

Exhibit 31.1	Certification - Robert L.G. Watson, CEO
Exhibit 31.2	Certification - Geoffrey R. King, CFO
Exhibit 32.1	Certification pursuant to 18 U.S.C. Section 1350 - Robert L.G. Watson, CEO
Exhibit 32.2	Certification pursuant to 18 U.S.C. Section 1350 - Geoffrey R. King, CFO

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ABRAXAS PETROLEUM CORPORATION

SIGNATURES

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

Date	May 10, 2017	By: /s/Robert L.G. Watson ROBERT L.G. WATSON, President and Principal Executive Officer
Date	May 10, 2017	By: /s/Geoffrey R. King GEOFFREY R. KING, Vice President and Principal Financial Officer
Date	May 10, 2017	By: /s/G. William Krog, Jr. G. WILLIAM KROG, JR., Principal Accounting Officer