ABRAXAS PETROLEUM CORP
Form 10-Q
November 09, 2016

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 September 30, 2016

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 | Smaller reporting company |

(Do not mark if a smaller reporting company)

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 November 7, 2016 was 135,088,301.

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.

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.

“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.

“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.

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“Possible reserves*” Possible reserves are those additional reserves that are less certain to be recovered than probable reserves

“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

ABRAXAS PETROLEUM CORPORATION
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PART II
OTHER INFORMATION

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Part I
FINANCIAL STATEMENTS

Item 1. Financial Statements

ABRAXAS PETROLEUM CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(in thousands)

| | September 30, 2016 (Unaudited) | December 31, 2015 |
|---|---|---|
| Assets | | |
| Current assets: | | |
| Cash and cash equivalents | $ — | $ 3,540 |
| Accounts receivable: | | |
| Joint owners, net | 2,038 | 1,552 |
| Oil and gas production sales | 9,556 | 6,713 |
| Other | 563 | 1,241 |
| | 12,157 | 9,506 |
| Derivative asset | 1,962 | 18,902 |
| Other current assets | 757 | 726 |
| Total current assets | 14,876 | 32,674 |
| Property and equipment: | | |
| Oil and gas properties, full cost method of accounting: | | |
| Proved | 797,673 | 787,683 |
| Other property and equipment | 37,784 | 41,444 |
| Total | 835,457 | 829,127 |
| Less accumulated depreciation, depletion, amortization and impairment | (690,135 ) | (604,289 ) |
| Total property and equipment, net | 145,322 | 224,838 |
| Deferred financing fees, net | 1,050 | 1,642 |
| Derivative asset | 914 | 8,463 |
| Other assets | 580 | 255 |
| Total assets | $ 162,742 | $ 267,872 |

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

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

| | September 30, 2016 (Unaudited) | December 31, 2015 |
|---|---|---|
| Liabilities and Stockholders' Equity | | |
| Current liabilities: | | |
| Accounts payable | $ 22,068 | $ 24,825 |
| Joint interest oil and gas production payable | 7,516 | 7,177 |
| Accrued interest | 53 | 115 |
| Other accrued expenses | 1,032 | 622 |
| Derivative liability | 1,586 | — |
| Current maturities of long-term debt | 1,313 | 2,330 |
| Total current liabilities | 33,568 | 35,069 |
| | | |
| Long-term debt – less current maturities | 93,680 | 138,402 |
| Other liabilities | 257 | 257 |
| Derivative liability long-term | 3,638 | — |
| Future site restoration | 8,577 | 9,679 |
| Total liabilities | 139,720 | 183,407 |
| | | |
| 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; 135,088,301 and 106,346,001 issued and outstanding, respectively | 1,351 | 1,063 |
| Additional paid-in capital | 343,198 | 313,852 |
| Accumulated deficit | (321,527) | (230,450) |
| Total stockholders' equity | 23,022 | 84,465 |
| Total liabilities and stockholders' equity | $ 162,742 | $ 267,872 |

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 September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| Revenues: | | | | |
| Oil and gas production revenues | $13,972 | $16,075 | $34,517 | $53,658 |
| Other | 4 | 2 | 31 | 24 |
| | 13,976 | 16,077 | 34,548 | 53,682 |
| Operating costs and expenses: | | | | |
| Lease operating | 4,599 | 5,236 | 13,609 | 17,806 |
| Production taxes | 1,200 | 1,569 | 3,602 | 5,255 |
| Rig expense | 192 | — | 534 | — |
| Depreciation, depletion, and amortization | 6,371 | 10,165 | 17,932 | 31,044 |
| Proved property impairment | 3,806 | 59,891 | 67,626 | 59,891 |
| General and administrative (including stock-based compensation of $768, $835, $2,410 and $3,085, respectively) | 2,760 | 2,654 | 8,238 | 9,190 |
| | 18,928 | 79,515 | 111,541 | 123,186 |
| Operating loss | (4,952) | (63,438) | (76,993) | (69,504) |
| Other (income) expense: | | | | |
| Interest income | — | — | (1) | (1) |
| Interest expense | 960 | 992 | 3,350 | 2,784 |
| Amortization of deferred financing fees | 151 | 161 | 763 | 481 |
| (Gain) loss on derivative contracts | (2,429) | (12,219) | 10,346 | (13,097) |
| (Gain) on sale of assets | (374) | — | (374) | — |
| | (1,692) | (11,066) | 14,084 | (9,833) |
| Loss from continuing operations before income tax | (3,260) | (52,372) | (91,077) | (59,671) |
| Income tax (expense) benefit | — | — | — | — |
| Net loss from continuing operations | (3,260) | (52,372) | (91,077) | (59,671) |
| Net loss from discontinued operations - net of tax | — | — | — | (20) |
| Net loss | $(3,260) | $(52,372) | $(91,077) | $(59,691) |
| Net loss per common share - basic | | | | |
| Continuing operations | $(0.02) | $(0.50) | $(0.77) | $(0.57) |
| Discontinued operations | — | — | — | — |
| | $(0.02) | $(0.50) | $(0.77) | $(0.57) |
| Net loss per common share - diluted | | | | |
| Continuing operations | $(0.02) | $(0.50) | $(0.77) | $(0.57) |
| Discontinued operations | — | — | — | — |
| | $(0.02) | $(0.50) | $(0.77) | $(0.57) |
| Weighted average shares outstanding: | | | | |
| Basic | 133,546 | 104,614 | 118,274 | 104,561 |
| Diluted | 133,546 | 104,614 | 118,274 | 104,561 |

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)

| | Nine Months Ended September 30, 2016 | 2015 |
|---|---|---|
| Operating Activities | | |
| Net loss | $(91,077) | $(59,691) |
| Loss from discontinued operations | — | (20) |
| Loss from continuing operations | (91,077) | (59,671) |
| Adjustments to reconcile net loss to net cash provided by (used in) operating activities: | | |
| Gain on sale of non oil and gas assets | (374) | — |
| Net loss (gain) on derivative contracts | 10,346 | (13,097) |
| Derivative contract settlements | 3,187 | 6,899 |
| Monetization of derivative contracts | 14,370 | 4,610 |
| Depreciation, depletion, and amortization | 17,932 | 31,044 |
| Proved property impairment | 67,626 | 59,891 |
| Amortization of deferred financing fees | 763 | 481 |
| Accretion of future site restoration | 381 | 426 |
| Stock-based compensation | 2,410 | 3,085 |
| Non-cash director compensation | 40 | — |
| Changes in operating assets and liabilities: | | |
| Accounts receivable | (2,651) | 9,592 |
| Other assets | 1,454 | 1,819 |
| Accounts payable and accrued expenses | (2,182) | (44,954) |
| Net cash provided by continuing operations | 22,225 | 125 |
| Net cash used in discontinued operations | — | (20) |
| Net cash provided by operating activities | 22,225 | 105 |
| | | |
| Investing Activities | | |
| Capital expenditures, including purchases and development of properties | (24,632) | (52,614) |
| Proceeds from the sale of oil and gas properties | 13,571 | 138 |
| Proceeds from the sale of non oil and gas assets | 4,022 | — |
| Net cash used in investing activities | (7,039) | (52,476) |
| | | |
| Financing Activities | | |
| Proceeds from long-term borrowings | 14,000 | 54,000 |
| Payments on long-term borrowings | (59,739) | (5,498) |
| Proceeds from issuance of common stock | 27,135 | — |
| Deferred financing fees | (171) | (72) |
| Exercise of stock options | 49 | 169 |
| Net cash (used in) provided by continuing operations | (18,726) | 48,599 |
| | | |
| Decrease in cash and cash equivalents | (3,540) | (3,772) |
| Cash and cash equivalents at beginning of period | 3,540 | 3,772 |
| Cash and cash equivalents at end of period | $— | $— |

| | | |
|---|---|---|
| Supplemental disclosures of cash flow information: | | |
| Interest paid | $3,395 | $2,756 |

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, 2015 filed with the SEC on March 15, 2016. 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 September 30, 2016 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, 2015.

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.

Reclassification of Prior Period Balances

Certain amounts in the prior period presented have been reclassified to conform to the current period financial statement presentation. These reclassifications have no effect on previously reported net loss.

New Accounting Standards and Disclosures

In August 2016, the FASB issued ASU No. 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments. The amended guidance addresses specific cash flow issues with the objective of reducing existing diversity in practice. The amendments in this update apply to all entities required to present a statement of cash flows. The amendments in this update are effective for public business entities for fiscal years beginning after December 15, 2017 and interim periods within those fiscal years. Early adoption is permitted, including adoption in an interim period. If an entity early adopts the amendments in an interim period, any adjustments should be reflected as of the beginning of the fiscal year that includes that interim period. An entity that elects early adoption must adopt all of the amendments in the same period. Amendments should be applied using a retrospective transition method to each period presented. If it is impracticable to apply the amendments retrospectively for some of the issues, the amendments for those issues would be applied prospectively as of

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the earliest date practicable. The Company has not yet determined what the effects of adopting this updated guidance will be on its statement of cash flows.

In March 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2016-06, Derivatives and Hedging (Topic 815): Contingent put and call options in debt instruments, which clarifies the requirements for assessing whether contingent call (put) options that can accelerate the payment of principal on debt instruments are clearly and closely related to their debt hosts. The amendment will be effective prospectively for reporting periods beginning on or after December 31, 2016, and early adoption is permitted. The Company is currently assessing the impact of the ASU on the Company's condensed consolidated financial statements.

In March 2016, the FASB issued ASU No. 2016-08, Revenue from Contracts with Customers (Topic 606): Principal Versus Agent Considerations (reporting revenue gross versus net), which clarifies the implementation guidance on principle versus agent considerations. The amendment will be effective prospectively for reporting periods beginning on or after December 31, 2017, and early adoption is not permitted. The Company is currently assessing the impact of the ASU on the Company's condensed consolidated financial statements.

In March 2016, the FASB issued ASU No. 2016-09, Compensation – Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting, which includes provisions intended to simplify various aspects related to how share-based compensation payments are accounted for and presented in the financial statements. This amendment will be effective prospectively for reporting periods beginning on or after December 15, 2016, and early adoption is permitted. The Company is currently assessing the impact of the ASU on the Company's condensed consolidated financial statements.

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 September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|
| 2016 | 2015 | 2016 | 2015 |
| $579 | $463 | $1,514 | $1,917 |

The following table summarizes the Company’s stock option activity for the nine months ended September 30, 2016 (shares in thousands):

| | Number of Shares | Weighted Average Option Exercise Price Per Share | Weighted Average Grant Date Fair Value Per Share |
|---|---|---|---|
| Outstanding, December 31, 2015 | 6,808 | $ 2.89 | $ 2.06 |

| | | | |
|---|---|---|---|
| Granted | 2,264 | 1.02 | 0.68 |
| Exercised | (50 ) | 0.99 | 0.71 |
| Cancelled/Forfeited | (528 ) | 2.82 | 1.93 |
| Outstanding, September 30, 2016 | 8,494 | $ 2.41 | $ 1.71 |

Additional information related to stock options at September 30, 2016 and December 31, 2015 is as follows:

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As of September 30, 2016, there was approximately $3.3 million of unamortized compensation expense related to outstanding stock options that will be recognized in 2016 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 nine months ended September 30, 2016:

| | Number of Shares (thousands) | Weighted Average Grant Date Fair Value Per Share |
|---|---|---|
| Unvested, December 31, 2015 | 1,643 | $ 3.44 |
| Granted | — | — |
| Vested/Released | (42 ) | 2.16 |
| Forfeited | (99 ) | 3.63 |
| Unvested, September 30, 2016 | 1,502 | $ 3.47 |

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

| Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|
| 2016 | 2015 | 2016 | 2015 |
| $189 | $372 | $896 | $1,168 |

As of September 30, 2016, there was approximately $2.2 million of unamortized compensation expense relating to outstanding restricted shares that will be recognized in 2016 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 September 30, 2015 our net capitalized costs of oil and gas properties exceeded the present value of our estimated proved reserves by approximately $59.9 million, resulting in the recognition of an impairment for the three and nine months ended of $59.9 million. At September 30, 2016, our net capitalized costs of oil and gas properties exceeded the cost ceiling of our estimated proved reserves by approximately $3.8 million, resulting in the recognition of a proved property impairment for the three and nine months then ended of $3.8 million and $67.6 million respectively. 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 continue to 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 nine months ended September 30, 2016 and the year ended December 31, 2015:

| | September 30, 2016 | December 31, 2015 |
|---|---|---|
| Beginning future site restoration obligation | $ 9,679 | $ 9,495 |
| New wells placed on production and other | 29 | 307 |
| Deletions related to property disposals and plugging costs | (1,427) | (793) |
| Accretion expense | 381 | 565 |
| Revisions and other | (85) | 105 |
| Ending future site restoration obligation | $ 8,577 | $ 9,679 |

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 and nine months ended September 30, 2016, there was no income tax benefit due to the fact we are in a loss position and have recorded a full valuation allowance against our net deferred taxes.

The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. As of September 30, 2016, the Company did not have any accrued interest or penalties related to uncertain tax positions. The tax years 2012 through 2015 remain open to examination by the tax jurisdictions to which the Company is subject.

At December 31, 2015, the Company had, subject to the limitation discussed below, $201.9 million of net operating loss carryforwards for U.S. tax purposes.  The loss carryforward will expire in varying amounts through 2035, if not utilized.

Uncertainties exist as to the future utilization of the operating loss carryforwards therefore, we have established a valuation allowance of $103.7 million for deferred tax assets at December 31, 2015.

3. Long-Term Debt

The following is a description of the Company’s debt as of September 30, 2016 and December 31, 2015, respectively:

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| | September 30, 2016 | December 31, 2015 |
|---|---|---|
| Senior secured credit facility | $ 90,000 | $ 134,000 |
| Rig loan agreement | 1,065 | 2,620 |
| Real estate lien note | 3,928 | 4,112 |
| | 94,993 | 140,732 |
| Less current maturities | (1,313 ) | (2,330 ) |
| | $ 93,680 | $ 138,402 |

Credit Facility

We have 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 September 30, 2016, $90.0 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. 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. 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.

At September 30, 2016, we had a borrowing base of $130.0 million, based on an amendment on April 22, 2016, which we refer to as the April 2016 Amendment. In accordance with the terms of the April 2016 Amendment, the borrowing base was automatically reduced to $120.0 million effective October 1, 2016. The borrowing base was further reduced to $115.0 million on October 31, 2016 in connection with the regularly scheduled redetermination, which we refer to as the Fall 2016 Redetermination.

Outstanding amounts under the credit facility bear interest (x) at any time an event of default exists, at 3% per annum plus the amounts set forth below, (y) from April 1, 2016 to October 1, 2016 0.25% per annum plus the rates set forth below and (z) at all other times, at (a) 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, (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 September 30, 2016, the interest rate on the credit facility was approximately 3.02% 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, other than Raven Drilling. In connection with the April 2016 Amendment, we also agreed to grant our lenders a security interest in our headquarters building (in addition to the lien granted to the lender under our building loan described below) and two ranches we own, none of which had previously secured our obligations under the credit facility. One of the ranches was sold in September 2016 in connection with the sale of our Portilla oil and gas properties.

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

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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 the office building, Raven Drilling's rig loan and obligations with respect to surety bonds and derivative contracts.

At September 30, 2016, we were in compliance with all of our debt covenants. As of September 30, 2016, the interest coverage ratio was 9.65 to 1.00, the total debt to EBITDAX ratio was 2.37 to 1.00, and our current ratio was 1.73 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 April 2016 Amendment, also included certain additional covenants including:

- 100% of the net proceeds from any sale of any of our properties occurring between April 1, 2016 and October 1, 2016 must be used to repay amounts outstanding under the credit facility;

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

- 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; and

- granting the lenders a security interest in at least 90% of the PV-10 of our proven reserves.

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.

Rig Loan Agreement

On September 19, 2011, Raven Drilling entered into a rig loan agreement, secured by our Oilwell 2,000 HP diesel electric drilling rig (the "Collateral"). The original principal amount of the note was $7.0 million and bears interest at 4.26%. The note is payable in monthly interest and principal payments in the amount of $179,695. Subject to earlier prepayment provisions and events of default, the stated maturity date of the note is February 14, 2017. As of September 30, 2016 and December 31, 2015, $1.1 million and $2.6 million, respectively, were outstanding under the rig loan agreement.

The Company has guaranteed Raven Drilling's obligations under the rig loan agreement and associated note. Obligations under the rig loan agreement are secured by a first priority perfected security interest, subject to certain permitted encumbrances, in the Collateral.

Real Estate Lien Note

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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 September 30, 2016 and December 31, 2015, $3.9 million and $4.1 million, respectively, were outstanding on the note.

4. Earnings per Share

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

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| | (In thousands, except per share data) | | | |
| Numerator: | | | | |
| Net loss from continuing operations | $(3,260) | $(52,372) | $(91,077) | $(59,671) |
| Net loss from discontinued operations | — | — | — | (20) |
| | (3,260) | (52,372) | (91,077) | (59,691) |
| Denominator: | | | | |
| Denominator for basic earnings per share – weighted-average common shares outstanding | 133,546 | 104,614 | 118,274 | 104,561 |
| Effect of dilutive securities: Stock options and restricted shares | — | — | — | — |
| Denominator for diluted earnings per share – adjusted weighted-average shares and assumed exercise of options and restricted shares | 133,546 | 104,614 | 118,274 | 104,561 |
| | | | | |
| Net loss per common share - basic | | | | |
| Continuing operations | $(0.02) | $(0.50) | $(0.77) | $(0.57) |
| Discontinued operations | — | — | — | — |
| | $(0.02) | $(0.50) | $(0.77) | $(0.57) |
| | | | | |
| Net loss per common share - diluted | | | | |
| Continuing operations | $(0.02) | $(0.50) | $(0.77) | $(0.57) |
| Discontinued operations | — | — | — | — |
| | $(0.02) | $(0.50) | $(0.77) | $(0.57) |

Basic earnings per share, excluding any dilutive effects of stock options and unvested restricted stock, is computed by dividing net loss available to common stockholders by the weighted average number of common shares outstanding for the period. Diluted loss per share is computed similar to basic; however diluted loss per share reflects the assumed conversion of all potentially dilutive securities. For the three and nine months ended September 30, 2016, 1,766 and 1,724 potential shares related to unvested restricted shares and options were excluded from the calculation of diluted loss per share since their inclusion would have been anti-dilutive due to losses incurred in the periods.

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.

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The following table sets forth the summary position of our derivative contracts as of September 30, 2016:

Fixed price swaps:

| | Oil - WTI | |
|---|---|---|
| Contract Periods | Daily Volume (Bbl) | Swap Price (per Bbl) |
| 2016 October - December | 2,500 | $43.25 |
| 2017 | 2,401 | $54.53 |
| 2018 | 1,796 | $47.48 |

Subsequent to September 30, 2016, we entered into the following derivative contracts.

| | Oil - WTI | |
|---|---|---|
| Contract Periods | Daily Volume (Bbl) | Swap Price (per Bbl) |
| 2019 | 1,197 | $54.54 |

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

Fair Value of Derivative Contracts as of September 30, 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 | $1,962 | Derivatives – current | $1,586 |
| Commodity price derivatives | Derivatives – long-term | 914 | Derivatives – long-term | 3,638 |
| | | $2,876 | | $5,224 |

Fair Value of Derivative Contracts as of December 31, 2015

| | 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 | $ 18,902 | Derivatives – current | $ — |
| Commodity price derivatives | Derivatives – long-term | 8,463 | Derivatives – long-term | — |
| | | $ 27,365 | | $ — |

Gains and losses from derivative activities are reflected as “(Gain) loss on derivative contracts” in the accompanying Condensed Consolidated Statements of Operations.

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.

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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 tables sets forth information about the Company's assets and liabilities measured at fair value on a recurring basis as of September 30, 2016 and December 31, 2015, 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 September 30, 2016 |
|---|---|---|---|---|
| Assets: | | | | |
| NYMEX Fixed Price Derivative contracts | $ — | $ 2,876 | $ — | $ 2,876 |
| Total Assets | $ — | $ 2,876 | $ — | $ 2,876 |
| Liabilities: | | | | |
| NYMEX Fixed Price Derivative contracts | $ — | $ 5,224 | $ — | $ 5,224 |
| Total Liabilities | $ — | $ 5,224 | $ — | $ 5,224 |

| | 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, 2015 |
|---|---|---|---|---|
| Assets: | | | | |
| NYMEX Fixed Price Derivative contracts | $ — | $ 21,731 | $ — | $ 21,731 |
| NYMEX Collars | — | — | 5,634 | 5,634 |
| Total Assets | $ — | $ 21,731 | $ 5,634 | $ 27,365 |

The Company's derivative contracts consisted of NYMEX-based fixed price swaps as of September 30, 2016, and NYMEX-based fixed price swaps and three-way collar contracts as of December 31, 2015. Under fixed price swaps, we receive a fixed price for our production and pay a variable market price to the contract counter-party. Three-way collar contracts combine a long put, a short put and a short call. 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 use of the long put combined with a short put allows us to sell a call at a higher price, thus establishing a higher ceiling and limits our exposure to future settlement payments while also restricting our downward risk to the difference between the long put and the short put if the price drops below the price of the short put. This allows us to settle our contracts for the market price plus the spread between the short put and the long put in a case where the market price has fallen below the short put fixed price. The NYMEX-based fixed price derivative contracts and three-way 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 swap contracts 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 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 nine months ended September 30, 2016.

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| | | |
|---|---|---|
| Unobservable inputs at January 1, 2016 | $ | 5,634 |
| Changes in market value | (2,151 | ) |
| Settlements during the period | (3,483 | ) |
| Unobservable inputs at September 30, 2016 | $ | — |

Nonrecurring Fair Value Measurements

The Company records certain assets and liabilities at fair value related to certain nonfinancial assets and liabilities that may be acquired in a business combination and thereby measured at fair value and the initial recognition of future site restoration obligations for which fair value is used.

The future site restoration 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 future site restoration 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 September 30, 2016, 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 September 30, 2016 our Borrowing Base was redetermined to $115.0 million. This Borrowing Base is fully conforming and represents a $5.0 million reduction from the Company's previously fully conforming Borrowing Base of $120.0 million. All other terms of the borrowing base remain unchanged.

In connection with the redetermination of the Borrowing Base, we entered into the following derivative contracts.

| Contract Periods | Oil - WTI Daily Volume (Bbl) | Swap Price (per |
|---|---|---|

| | | |
|---|---|---|
| | | Bbl) |
| 2019 | 1,197 | $54.54 |

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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, 2015 filed with the SEC on March 15, 2016, 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, 2015.

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. We focus on assets with a high working interest and low geologic risk as well as operational and infrastructure control. We seek strong full cycle rate of return and low risk exploitable upside using the Company's operating experience. We believe that we have a number of development opportunities on our properties and intend to expand upon our development activities with complementary exploration projects 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, gas and NGL;

- 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 demand for, and 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 of oil, NGL and gas in 2015, and during the first nine months of 2016, have impacted the amount of cash generated from operating activities, and have in turn impacted our financial position.

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During the nine months ended September 30, 2016, the NYMEX future price for oil averaged $41.54 per Bbl as compared to $50.98 per Bbl in 2015. During the nine months ended September 30, 2016, the NYMEX future spot price for gas averaged $2.35 per MMBtu compared to $2.76 per MMBtu in 2015. Prices closed on September 30, 2016 at $48.24 per Bbl of oil and $2.91 per MMBtu of gas, compared to closing on September 30, 2015 at $45.09 per Bbl of oil and $2.52 per MMBtu of gas. At November 7, 2016, prices closed at $44.89 per Bbl of oil and $2.82 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 remain depressed or continue to 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.

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 nine months ended September 30, 2016 and 2015:

| | Oil - NYMEX | | Gas - NYMEX | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| Average realized price (1) | $34.13 | $42.94 | $1.10 | $2.16 |
| Average NYMEX price | 41.54 | 50.98 | 2.35 | 2.76 |
| Differential | $(7.41 ) | $(8.04 ) | $(1.25) | $(0.60) |

(1) Excludes the impact of derivative activities.

At September 30, 2016, our derivative contracts consisted of fixed price swaps. Under fixed price swaps, we receive a fixed price for our production and pay a variable market price to the contract counter-party.

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 June 30, 2016) through December 31, 2016, 90% in 2017, 88% in 2018 and 81% for 2019. 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 nine months ended September 30, 2016, we realized a loss of $10.3 million, consisting of a gain of $3.2 million on closed contracts and a loss of $13.5 million related to open contracts. For the nine months ended September 30, 2015, we realized a gain of $13.1 million consisting of a gain of $6.9 million on closed contracts and a gain of $6.2 million related to open contracts. We have not designated any of these derivative contracts as hedges as prescribed by applicable accounting rules.

The following table sets forth our derivative contracts at September 30, 2016:

Fixed Price Swaps:

| Contract Periods | Oil - WTI Daily Volume (Bbl) | Swap Price (per Bbl) |
|---|---|---|
| 2016 October - December | 2,500 | $43.25 |
| 2017 | 2,401 | $54.53 |

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| | | |
|---|---|---|
| 2018 | 1,796 | $47.48 |

Subsequent to September 30, 2016 we entered into the following derivative contracts.

| Contract Periods | Oil - WTI Daily Volume (Bbl) | Swap Price (per Bbl) |
|---|---|---|
| 2019 | 1,197 | $54.54 |

At September 30, 2016, the aggregate fair market value of our commodity derivative contracts was a net liability of approximately $2.3 million.

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 estimates as of December 31, 2015, we anticipate our proved developed producing reserves to decline 33%, 26% and 15% in 2017, 2018 and 2019, respectively. Thereafter our reserves are expected to decline an estimated 10% annually. 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 nine months ended September 30, 2016 of $24.6 million related to our exploration and development activities. We are authorized to make capital expenditures in 2016 of up to $40.0 million. Based on current service cost trends, we anticipate capital expenditures to be approximately $35.0 million in 2016. The 2016 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 and nine months ended September 30, 2016 and 2015:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| Total production (MBoe) | 548 | 552 | 1,531 | 1,643 |
| Average daily production (Boepd) | 5,955 | 6,004 | 5,586 | 6,020 |
| % Oil | 61 % | 66 % | 60 % | 67 % |

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, and if appropriate opportunities are available, issuing debt or equity securities, selling assets or monetizing our derivative contracts, although we may not be able to complete any such transactions on terms acceptable to us, if at all. On May 25, 2016, we completed a stock offering of 28.8 million shares of common stock for net proceeds of approximately $27.2 million. The net proceeds from this stock issuance were used to repay borrowings under our credit facility. As of September 30, 2016 our borrowing base was $130.0 million. Under the terms of the April 2016 Amendment, the borrowing base was automatically reduced to $120.0 million on October 1, 2016. The borrowing base was further reduced to $115.0 million on October 31, 2016 in connection with the Fall 2016 Redetermination.

Borrowings and Interest. At September 30, 2016, we had a total of $90.0 million outstanding under our credit facility and total indebtedness of $95.0 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.

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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, 2015, 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, 2015, we drilled or participated in 145 gross (55.8 net) wells of which 97% were 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 60% of our estimated proved reserves on a Boe basis (19% on a PV-10 basis) at December 31, 2015 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

Williston Basin
At our North Fork prospect, in McKenzie County, North Dakota, the Stenehjem 10H, 12H and 14H wells targeting the Three Forks averaged 1,059 Boepd (786 barrels of oil per day, 1,642 Mcf of natural gas per day) over their first 30 days of production. The Stenehjem 11H, 13H and 15H wells targeting the Middle Bakken averaged 1,226 Boepd (915 barrels of oil per day, 1,864 Mcf of natural gas per day) over their first 30 days of production. We own a working interest of approximately 78% in Stenehjem 10H-15H.

The 30-day average rates represent the highest 30 days of production and do not include the impact of natural gas liquids and shrinkage at the processing plant and include flared gas.

Austin Chalk
At our Jourdanton prospect in Atascosa County, Texas, the Bulls Eye 101H is currently on production. Although the well has not achieved the anticipated initial production rate to date, it did achieve reasonable production rates and has shown a very stable production profile. The well continues to clean up having recovered approximately 40% of its load water and over 15,000 Boes to date. We will update the market with more specific numbers once volumes stabilize. We own a 100% working interest in the Bulls Eye 101H.

Permian
In Ward County, Texas, we successfully drilled the Caprito 99-101H to a total depth of 15,665 feet. The completion of the Caprito 99-101H has been delayed due to completion issues on a third party’s well, which has delayed the arrival of the frac fleet. We have been advised by the third party frac company that the rig up date for our planned 25 stage completion of the Caprito 99-101H is now November 9. We own a 100% working interest in the Caprito 99-101H.

2016 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 continue to be depressed for the remainder of 2016. Although changes in OPEC production strategies, geopolitical risks or other factors could impact current forecasts, we anticipate weak commodity prices throughout 2016. Depressed prices for oil, gas and NGL will likely have a material adverse effect on our results of operations and liquidity. Our primary sources of liquidity are cash flow from operations, borrowings under our credit facility, sales of non-core assets and other capital transactions, when available. 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. Our consolidated cash flow from operations increased in the first nine months of 2016 primarily as a result of the monetization of some of our derivative positions. Availability under our credit facility is currently subject to a borrowing base of $115.0 million based on the Fall 2016 Redetermination . The amount of

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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 sharp decline in commodity prices, we recorded an impairment to our proved properties of $128.6 million for the year ended December 31, 2015 and an additional impairment of $67.6 million for the first nine months of 2016. The amount of any additional impairment is contingent upon many factors such as the price of oil, gas and NGL for the remainder of 2016, increases or decreases in our reserve base, changes in estimated costs and expenses, and oil and gas property acquisitions, which could increase, decrease or eliminate the need for such impairments.

While we will continue to operate and develop our portfolio of assets, we are committed to protecting our balance sheet and managing our capital programs. For 2017, Abraxas anticipates drilling expenditures to approximate cash flow. As a result, we can significantly reduce our capital budget in response to lower commodity prices. We are also committed to reducing our general and administrative, or "(G&A)" and field-level operating costs commensurate with our reduced, but focused, activity level. Abraxas President and CEO took a voluntary salary reduction of 20% effective September 1, 2015, and effective February 1, 2016, the remaining named executive officers of Abraxas took a voluntary salary reduction of 20%.

Results of Operations

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

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| Operating revenue (1): | | | | |
| Oil sales | $12,713 | $14,414 | $31,380 | $47,240 |
| Gas sales | 1,014 | 1,345 | 2,444 | 4,844 |
| NGL sales | 245 | 316 | 693 | 1,574 |
| Other | 4 | 2 | 31 | 24 |
| Total operating revenues | $13,976 | $16,077 | $34,548 | $53,682 |
| Operating loss | $(4,952 ) | $(63,438) | $(76,993) | $(69,504) |
| Oil sales (MBbls) | 334 | 365 | 919 | 1,100 |
| Gas sales (MMcf) | 765 | 750 | 2,232 | 2,246 |
| NGL sales (MBbls) | 86 | 62 | 239 | 169 |
| Oil equivalents (MBoe) | 548 | 552 | 1,531 | 1,643 |
| Average oil sales price (per Bbl)(1) | $38.08 | $39.50 | $34.13 | $42.94 |
| Average gas sales price (per Mcf)(1) | $1.32 | $1.79 | $1.10 | $2.16 |
| Average NGL sales price (per Bbl) | $2.83 | $5.07 | $2.90 | $9.32 |
| Average oil equivalent sales price (Boe) (1) | $25.50 | $29.10 | $22.55 | $32.65 |

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

Comparison of Three Months Ended September 30, 2016 to Three Months Ended September 30, 2015

Operating Revenue. During the three months ended September 30, 2016, operating revenue decreased to $14.0 million from $16.1 million for the same period of 2015. The decrease in revenue was primarily due to lower prices for all products as well as lower sales volumes for oil. Lower realized commodity prices had a negative impact on revenue of $1.0 million of which $0.5 million was attributable to oil. Lower oil sales volumes had a negative impact on revenue of approximately $1.2 million for the three months ended September 30, 2016.

Oil sales volumes decreased to 334 MBbl during the three months ended September 30, 2016 from 365 MBbl for the same period of 2015. The decrease in oil sales volume was primarily due to natural field declines and property sales. We sold non-core assets effective June 1, 2016 which contributed 14.4 MBbl in the third quarter of 2015. Production decreases

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were partially offset by new wells brought on line since the third quarter of 2015 which contributed 150 MBbl for the three months ended September 30, 2016. Gas sales volumes increased to 765 MMcf for the three months ended September 30, 2016 from 750 MMcf for the same period of 2015. The increase in gas production was due to new wells brought on line since September 30, 2015 which contributed 184 MMcf for the three months ended September 30, 2016, which was partially offset by natural declines as well as pipeline constraints. NGL sales volumes increased to 86 MBbl for the three months ended September 30, 2016 from 62 MBbl for the same period of 2015. 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 September 30, 2016 decreased to $4.6 million from $5.2 million for the same period in 2015. Due to the decline in commodity prices, there has been a decrease in the cost of services. Additionally we have focused on lowering LOE and shutting in marginal wells, as well as sales of non-core properties. We have also significantly reduced our non-recurring projects. LOE per Boe for the three months ended September 30, 2016 was $8.40 compared to $9.48 for the same period of 2015. The decrease per Boe was due to lower costs incurred for the three months ended September 30, 2016 as compared to the same period of 2015.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the three months ended September 30, 2016 decreased to $1.2 million from $1.6 million for the same period of 2015. The decrease was due to lower commodity prices and lower sales volumes. Production taxes for the three month ended September 30, 2016 were 9% of total oil, gas and NGL sales compared to 10% for the same period of 2015.

General and Administrative (“G&A”) Expense. G&A expenses, excluding stock-based compensation, for the three months ended September 30, 2016 increased to $2.0 million from $1.8 million for the same period of 2015. The increase in G&A expense was primarily the result of less G&A expense being capitalized due to decrease drilling activities, which was offset by cost savings measures, including salary reductions. G&A expense per Boe, excluding stock-based compensation, was $3.64 for the quarter ended September 30, 2016 compared to $3.29 for the same period of 2015. The increase per Boe was primarily due to higher costs and lower production.

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 is recognized over their vesting period. For the three months ended September 30, 2016 and 2015, stock-based compensation was $0.8 million for each period.

Depreciation, Depletion and Amortization (“DD&A”) Expense. DD&A expense for the three months ended September 30, 2016 decreased to $6.4 million from $10.2 million for the same period of 2015. The decrease was primarily the result of a reduction in the full cost pool as a result of the proved property impairment in 2015 and the first nine months of 2016. DD&A expense per Boe for the three months ended September 30, 2016 was $11.63 compared to $18.40 in 2015.

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 September 30, 2016, our net capitalized costs of oil and gas properties exceeded the cost ceiling of our estimated proved reserves by approximately $3.8 million, resulting in the recognition of a proved property impairment of the same amount. As of September 30, 2015, our net capitalized costs of oil and gas properties exceeded the cost ceiling of our estimated proved reserves by approximately $59.9 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.

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Interest Expense. Interest expense for the three months ended September 30, 2016 and 2015 was constant at $1.0 million. Although overall debt levels were lower for the three months ended September 30, 2016 as compared to 2015, our interest rate was slightly higher for the three months ended September 30, 2016 as compared to 2015.

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 as of September 30, 2016, and NYMEX-based fixed price swaps and three-way collar contracts as of September 30, 2015. The estimated value of our commodity derivative contracts was a net liability of approximately $2.3 million as of September 30, 2016. 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 September 30, 2016, we recognized a gain on our commodity derivative contracts of $2.4 million, consisting of a loss on closed contracts of $1.1 million and a gain of $3.5 million relating to open contracts. For the three months ended September 30, 2015, we recognized a gain on our commodity derivative contracts of $12.2 million, consisting of a gain of $1.7 million on closed contracts and a gain of $10.5 million related to open contracts. We monetized a portion of our derivative contracts in March and April 2016. Cash flows from future settlements are expected to decrease as a result.

Income Tax Expense. For the three months ended September 30, 2016 and 2015 there was no income tax expense recognized as a result of NOL carryforwards and a net loss in the three months ended September 30, 2016 and 2015.

Comparison of Nine Months Ended September 30, 2016 to Nine Months Ended September 30, 2015

Operating Revenue. During the nine months ended September 30, 2016, operating revenue decreased to $34.5 million from $53.7 million for the same period of 2015. The decrease in revenue was primarily due to lower prices for all products as well as lower sales volumes for oil and gas. Lower realized commodity prices had a negative impact on revenue of $13.2 million, of which $9.7 million was attributable to oil. Lower sales volumes for oil and gas had a negative impact on revenue of $6.2 million.

Oil sales volumes decreased to 919 MBbl during the nine months ended September 30, 2016 from 1,100 MBbl for the same period of 2015. The decrease in oil sales volume was primarily due to natural field declines and sales of non-core properties. We sold non-core properties effective June 1, 2016 which contributed 43.8 MBbl during the first nine months of 2015. Production decreases were offset by new wells brought on line since the third quarter of 2015 which contributed 267 MBbl for the nine months ended September 30, 2016. Gas sales volumes decreased to 2,232 MMcf for the nine months ended September 30, 2016 from 2,246 MMcf for the same period of 2015. The decrease in gas sales was primarily due to natural field declines. Production decreases were partially offset by new wells brought on line. New wells brought onto production contributed 364 MMcf for the nine months ended September 30, 2016. NGL sales volumes increased to 239 MBbl for the nine months ended September 30, 2016 from 169 MBbl for the same period of 2015. The increase in NGL sales was primarily due to a higher percentage of our gas production from West Texas, North Dakota and the Eagle Ford that has a higher NGL content.

LOE. LOE for the nine months ended September 30, 2016 decreased to $13.6 million from $17.8 million for the same period of 2015. Due to the decline in commodity prices, there has been a decrease in the cost of services. Additionally, we have focused on lowering LOE and shutting in marginal wells. We have also significantly reduced non-recurring workover projects. LOE per Boe for the nine months ended September 30, 2016 was $8.89 compared to $10.83 for the same period of 2015. The decrease per Boe was due to lower service costs for the nine months ended September 30, 2016 as compared to the same period of 2015.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the nine months ended September 30, 2016 decreased to $3.6 million from $5.3 million for the same period of 2015. The decrease was primarily the result of lower commodity prices and lower sales volumes. Production taxes for the nine months ended September 30, 2016 and 2015 were 10% of total oil, gas and NGL sales.

G&A Expenses. G&A expenses, excluding stock-based compensation, decreased to $5.8 million for the first nine months of 2016 from $6.1 million for the same period of 2015. The decrease in G&A expense was primarily related to cost saving measures, including reduced salaries. G&A expense per Boe, excluding stock-based compensation expense, was $3.81 for the nine months ended September 30, 2016 compared to $3.71 for the same period of 2015. The increase per Boe was primarily due to the decrease in volumes produced offset by the lower costs in the first nine months of 2016 compared to the same period in 2015.

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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 is recognized over their vesting period. For the nine months ended September 30, 2016 stock based compensation was $2.4 million as compared to $3.1 million for the same period of 2015. The decrease was primarily due to option grants in 2016 at a lower stock price as compared to 2015.

DD&A Expenses. DD&A expense for the nine months ended September 30, 2016 decreased to $17.9 million from $31.0 million for same period of 2015. The decrease was primarily the result of a reduction in the full cost pool as a result of impairments in 2015 and 2016. Our DD&A expense per Boe for the nine months ended September 30, 2016 was $11.72 compared to $18.89 in 2015.

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 net 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 September 30, 2016, our net capitalized costs of oil and gas properties exceeded the cost ceiling of our estimated proved reserves by approximately $3.8 million, resulting in the recognition of a proved property impairment of the same amount. Total impairment for the nine months ended September 30, 2016 was $67.6 million, which includes $63.8 recognized in the first half of 2016. As of September 30, 2015, our net capitalized costs of oil and gas properties exceeded the cost ceiling of our estimated proved reserves by approximately $59.9 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 nine months ended September 30, 2016 was $3.3 million as compared to $2.8 million for the same period of 2015. The increase in 2016 was due to higher interest rates during the nine months of 2016 as compared to the same period of 2015.

Loss (Gain) on Derivative Contracts. We account for derivative contract gains and losses based on realized and unrealized amounts. The realized derivative gains or losses are determined by actual derivative settlements during the period. Unrealized gains and losses are based on the periodic mark to market valuation of derivative contracts in place. Our derivative contract transactions do not qualify for hedge accounting; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. During the nine months ended September 30, 2016, our derivative contracts consisted of commodity swaps. The net estimated value of our commodity derivative contracts was a net liability of approximately $2.3 million as of September 30, 2016. When our derivative contract prices are higher than prevailing market prices, we incur realized and unrealized gains and conversely, when our derivative contract prices are lower than prevailing market prices, we incur realized and unrealized losses. For the nine months ended September 30, 2016, we recognized a loss on our commodity derivative contracts of $10.3 million, consisting of a gain on closed contracts of $3.2 million and a loss of $13.5 million relating to open contracts. For the nine months ended September 30, 2015, we recognized a gain on our commodity derivative contracts of $13.1 million, consisting of a gain of $6.9 million on closed contracts and a gain of $6.2 million related to open contracts. We monetized a portion of our derivative contracts in March and April 2016. Cash flows from future settlements are expected to decrease as a result.

Income Tax Expense. For the nine months ended September 30, 2016 and 2015 there was no income tax expense recognized as a result of NOL carryforwards and a net loss in the nine months ended September 30, 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, and if appropriate opportunities are available, selling of debt or equity securities, selling assets or monetizing derivative contracts, although we may not be able to complete any such transactions on terms acceptable 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 2016 including our planned capital expenditures.

On September 20, 2016 we closed on the sale of our Portilla oil and gas properties as well as related surface for approximately $13.1 million. Proceeds from this sale were used to reduce amounts outstanding under our credit facility.

Capital Expenditures. Capital expenditures for the nine months ended September 30, 2016 and 2015 were $24.6 million and $52.6 million, respectively.

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

| | Nine Months Ended September 30, 2016 | 2015 |
|---|---|---|
| | (In thousands) | |
| Expenditure category: | | |
| Exploration/Development | $24,549 | $51,939 |
| Facilities and other | 83 | 675 |
| Total | $24,632 | $52,614 |

During the nine months ended September 30, 2016 and 2015 our expenditures were primarily for development of our existing properties. We are authorized to make capital expenditures in 2016 of up to $40.0 million. Based on current service cost trends, we anticipate capital expenditures to be approximately $35.0 million in 2016. The 2016 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.

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:

| | Nine Months Ended September 30, 2016 | 2015 |
|---|---|---|

| | (In thousands) | |
|---|---|---|
| Net cash provided by operating activities | $22,225 | $125 |
| Net cash (used in) investing activities | (7,039 ) | (52,476 ) |
| Net cash (used in) provided by financing activities | (18,726 ) | 48,599 |
| Total | $(3,540 ) | $(3,752 ) |

Operating activities for the nine months ended September 30, 2016 provided $22.2 million in cash compared to providing $0.1 million in the same period of 2015. Non-cash expense items, net changes in operating assets and liabilities and the monetization of hedges accounted for most of these funds. Investing activities used $7.0 million during the nine months ended September 30, 2016, capital expenditures of $24.6 million, and were offset by proceeds from sales of oil and gas properties of $13.6 million for the period. Investing activities for the nine months ended September 30, 2015 used $52.5

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million. Funds used during the nine months ended September 30, 2016 and 2015 were primarily for the development of our existing properties. Financing activities used $18.7 million for the nine months ended September 30, 2016 compared to providing $48.6 million for the same period of 2015. Funds used during the nine months ended September 30, 2016 were primarily payments on borrowings under our credit facility offset by proceeds from the equity offering in May 2016. Funds provided during the nine months ended September 30, 2015 were primarily proceeds from borrowings under our credit facility.

Future Capital Resources. Our principal sources of capital going forward are cash flow from operating activities, borrowings under our credit facility, cash on hand, and if appropriate opportunities are available, issuing of debt or equity securities, selling assets or monetizing our derivative contracts, although we may not be able to complete any such transactions on terms acceptable to us, if at all.

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 60% of our total estimated proved reserves on a Boe basis (19% on a PV-10 basis) at December 31, 2015 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 September 30, 2016:

| Contractual Obligations (In thousands) | Payments due in twelve month periods ending: Total | September 30, 2017 | September 30, 2018-2019 | September 30, 2020-2021 | Thereafter |
|---|---|---|---|---|---|
| Long-term debt (1) | $94,993 | $ 1,313 | $ 90,529 | $ 576 | $ 2,575 |
| Interest on long-term debt (2) | 5,661 | 2,899 | 2,336 | 248 | 178 |
| Lease obligations (3) | 76 | 43 | 33 | — | — |
| Total | $100,730 | $ 4,255 | $ 92,898 | $ 824 | $ 2,753 |

(1) These amounts represent the balances outstanding under our credit facility, the rig loan agreement 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.

(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, 2016 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 September 30, 2016, our reserve for these obligations totaled $8.6 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.

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Off-Balance Sheet Arrangements. At September 30, 2016 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 September 30, 2016, 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:

| | September 30, 2016 | December 31, 2015 |
|---|---|---|
| | (In thousands) | |
| Credit facility | $90,000 | $ 134,000 |
| Rig loan agreement | 1,065 | 2,620 |
| Real estate lien note | 3,928 | 4,112 |
| | 94,993 | 140,732 |
| Less current maturities | (1,313 ) | (2,330 ) |
| | $93,680 | $ 138,402 |

Credit Facility

We have 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 September 30, 2016, $90.0 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. 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. 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.

At September 30, 2016, we had a borrowing base of $130.0 million, based on the April 2016 Amendment. In accordance with the terms of the April 2016 Amendment, the borrowing base was automatically reduced to $120.0 million effective October 1, 2016. The borrowing base was further reduced to $115.0 million on October 31, 2016 in connection with the Fall 2016 Redetermination.

Outstanding amounts under the credit facility bear interest (x) at any time an event of default exists, at 3% per annum plus the amounts set forth below, (y) between April 1, 2016 and October 1, 2016 , 0.25% per annum plus the rates set forth below and (z) at all other times, at (a) 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, (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 September 30, 2016, the interest rate on the credit facility was approximately 3.02% 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, other than Raven Drilling. In connection with the April 2016 Amendment, we also agreed to grant our lenders a security interest in our headquarters building (in addition to the lien granted to the lender under our building loan described below) and two ranches we own, none of which had previously secured our obligations under the credit facility. One of the ranches was sold in September 2016 in connection with the sale of our Portilla oil and gas properties.

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 income (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 office building, Raven Drilling's rig loan and obligations with respect to surety bonds and derivative contracts.

At September 30, 2016 we were in compliance with all of our debt covenants. As of September 30, 2016, the interest coverage ratio was 9.65 to 1.00, the total debt to EBITDAX ratio was 2.37 to 1.00, and our current ratio was 1.73 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 April 2016 Amendment also included certain additional covenants including:

- 100% of the net proceeds from any sale of any of our properties occurring between April 1, 2016 and October 1, 2016 must be used to repay amounts outstanding under the credit facility;
- 100% of the net proceeds from any terminations of derivative contracts must be used to repay amounts outstanding under the credit facility;
- 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; and

- granting the lenders a security interest in at least 90% of the PV-10 of our proven reserves.

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.

Rig Loan Agreement

On September 19, 2011 Raven Drilling entered into a rig loan agreement, secured by our Oilwell 2,000 HP diesel electric drilling rig (the “Collateral”). The principal amount of the note was $7.0 million and bears interest at 4.26%. The note is payable in monthly interest and principal payments in the amount of $179,695. Subject to earlier prepayment provisions and events of default, the stated maturity date of the note is February 14, 2017. As of September 30, 2016 and December 31, 2015, $1.1 million and $2.6 million, respectively, were outstanding under the rig loan agreement.

The Company has guaranteed Raven Drilling’s obligations under the rig loan agreement and associated note. Obligations under the rig loan agreement are secured by a first priority perfected security interest, subject to certain permitted encumbrances, in the Collateral.

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 September 30, 2016 and December 31, 2015, $3.9 million and $4.1 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 79% of our estimated oil production from our net proved developed producing reserves (based on reserve estimates as of June 30, 2016) through December 31, 2016, 90% for 2017, 88% for 2018 and 81% for 2019.

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 nine months ended September 30, 2016, a 10% decline in oil and gas prices would have reduced our operating revenue, cash flow and net income by approximately $3.5 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 September 30, 2016, the aggregate fair market value of our commodity derivative contracts was a liability of approximately $2.3 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 September 30, 2016, we had $90.0 million of outstanding indebtedness under our credit facility. Effective April 1, 2016, outstanding amounts under the credit facility bear interest (x) at any time an event of default exists, at 3% per annum plus the amounts set forth below, (y) between April 1, 2016 to the earlier of October 1, 2016 and the effective date of the Fall 2016 Redetermination, 0.25% per annum plus the rates set forth below and (z) at all other times, at (a) 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, (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 September 30, 2016 the interest rate on the credit facility was approximately 3.02% assuming LIBOR borrowings. For every percentage point that the LIBOR rate rises, our interest expense would increase by approximately $0.9 million on an annual basis, based on our outstanding indebtedness as of September 30, 2016.

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 nine months ended September 30, 2016 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 September 30, 2016, 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, 2015, 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 | November 9, 2016 | By: /s/Robert L.G. Watson<br>ROBERT L.G. WATSON,<br>President and<br>Principal Executive Officer |
| Date | November 9, 2016 | By: /s/Geoffrey R. King<br>GEOFFREY R. KING,<br>Vice President and<br>Principal Financial Officer |
| Date | November 9, 2016 | By: /s/G. William Krog, Jr.<br>G. WILLIAM KROG, JR.,<br>Principal Accounting Officer |