ABRAXAS PETROLEUM CORP
Form 10-Q
May 09, 2014

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

FORM 10-Q
(Mark One)

ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2014

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 ý No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ýNo ¨

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 o	Accelerated filer x
Non-accelerated filer o (Do not mark if a smaller reporting company)	Smaller reporting company o

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

The number of shares of the issuer's common stock outstanding as of May 8, 2014 was 93,796,854.

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;
- our success in development, exploitation and exploration activities;
- the availability of capital;
- our ability to make planned capital expenditures;
- declines in our production of oil and gas;
- our ability to procure services and equipment for our drilling and completion activities;
- our restrictive debt covenants;
- political and economic conditions in oil producing countries, especially those in the Middle East;
- price and availability of alternative fuels;
- 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 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 an 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:

“Proved reserves” are those quantities of oil and gas reserves, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable - from a given date forward, from known

reservoirs, and under defined economic conditions, operating methods, and government regulations.

“Proved developed reserves” are those quantities of oil and gas reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional reserves expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included in “proved developed reserves” only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

“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 undeveloped reserves” or “PUDs” are those quantities of oil and gas reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for development. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with reasonable certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proven effective by actual tests in the area and in the same reservoir.

“Probable reserves” are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves.

“Possible reserves” are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than probable reserves.

“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.”

ABRAXAS PETROLEUM CORPORATION
FORM 10 – Q
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PART I
FINANCIAL INFORMATION

Item 1. Financial Statements

Abraxas Petroleum Corporation
Condensed Consolidated Balance Sheets
(in thousands)

	March 31, 2014 (Unaudited)	December 31, 2013
Assets		
Current assets:		
Cash and cash equivalents	$349	$5,205
Accounts receivable, net:		
Joint owners	7,710	15,493
Oil and gas production	19,013	16,625
Other	75	1,497
	26,798	33,615
Derivative asset – current	218	85
Other current assets	529	644
Total current assets	27,894	39,549
Property and equipment:		
Oil and gas properties, full cost method of accounting:		
Proved	597,615	564,755
Other property and equipment	38,684	38,959
Total	636,299	603,714
Less accumulated depreciation, depletion, and amortization	(429,408)	(423,069)
Total property and equipment – net	206,891	180,645
Deferred financing fees, net	1,791	2,140
Derivative asset – long-term	547	925
Other assets	391	391
Total assets	$237,514	$223,650

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

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Abraxas Petroleum Corporation
Condensed Consolidated Balance Sheets (continued)
(in thousands, except share data)

	March 31, 2014 (Unaudited)	December 31, 2013
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$40,904	$52,793
Oil and gas production payable	16,961	23,810
Accrued interest	65	31
Other accrued expenses	1,716	1,231
Derivative liability – current	2,860	2,728
Current maturities of long-term debt	2,158	2,142
Total current liabilities	64,664	82,735
Long-term debt, excluding current maturities	68,404	41,790
Other liabilities	57	57
Derivative liability – long-term	2,510	2,274
Future site restoration	9,846	9,888
Total liabilities	145,481	136,744
Stockholders' Equity		
Preferred stock, par value $0.01 per share, authorized 1,000,000 shares; -0- issued and outstanding	—	—
Common stock, par value $0.01 per share, authorized 200,000,000 shares; 93,676,095 and 92,906,049 issued and outstanding, respectively	937	929
Additional paid-in capital	253,670	253,193
Accumulated deficit	(161,905)	(166,609)
Accumulated other comprehensive (loss) income	(669)	(607)
Total stockholders' equity	92,033	86,906
Total liabilities and stockholders' equity	$237,514	$223,650

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

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Abraxas Petroleum Corporation
Condensed Consolidated Statements of Operations
(Unaudited)
(in thousands except per share data)

	Three Months Ended March 31,	
	2014	2013
Revenue:		
Oil and gas production revenues	$25,850	$21,163
Other	43	33
	25,893	21,196
Operating costs and expenses:		
Lease operating expenses	5,892	6,462
Production taxes	2,204	1,927
Depreciation, depletion, and amortization	7,635	6,509
General and administrative (including stock-based compensation of $439 and $474 respectively)	2,823	2,530
	18,554	17,428
Operating income	7,339	3,768
Other (income) expense:		
Interest income	—	(1)
Interest expense	608	1,208
Amortization of deferred financing fees	348	333
Loss on derivative contracts - Realized	734	925
Loss on derivative contracts - Unrealized	945	621
Other	—	87
	2,635	3,173
Net income before income tax expense	4,704	595
Income tax expense	—	—
Net income	$4,704	$595
Net income per common share – basic	$0.05	$0.01
Net income per common share – diluted	$0.05	$0.01
Weighted average shares outstanding:		
Basic	92,566	92,290
Diluted	94,321	93,264

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

Abraxas Petroleum Corporation
Condensed Consolidated Statements of
Other Comprehensive Income (Loss)
(Unaudited)
(in thousands)

	Three Months Ended March 31,	
	2014	2013
Consolidated net income	$4,704	$595
Other comprehensive income (loss):		
Change in unrealized value of investments	—	(7)
Foreign currency translation adjustment	(62)	(131)
Other comprehensive income (loss)	(62)	(138)
Comprehensive income	$4,642	$457

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

Abraxas Petroleum Corporation
Condensed Consolidated Statements of Cash Flows
(Unaudited)
(in thousands)

	Three Months Ended March 31,	
	2014	2013
Operating Activities		
Net income	$4,704	$595
Adjustments to reconcile net income to net cash provided by operating activities:		
Change in derivative fair value	613	592
Depreciation, depletion, and amortization	7,635	6,509
Amortization of deferred financing fees	348	333
Accretion of future site restoration	144	172
Stock-based compensation	439	474
Changes in operating assets and liabilities:		
Accounts receivable	6,812	(8,804)
Other	113	(69)
Accounts payable and accrued expenses	(18,384)	10,111
Net cash provided by operating activities	2,424	9,913
Investing Activities		
Capital expenditures, including purchases and development of properties	(36,719)	(17,773)
Proceeds from sale of oil and gas properties	2,782	—
Net cash used in investing activities	(33,937)	(17,773)
Financing Activities		
Proceeds from long-term borrowings	27,000	12,000
Payments on long-term borrowings	(370)	(6,047)
Exercise of stock options	46	—
Other	(20)	—
Net cash provided by financing activities	26,656	5,953
Effect of exchange rate changes on cash	1	—
Decrease in cash	(4,856)	(1,907)
Cash and equivalents, at beginning of period	$5,205	$2,061
Cash and equivalents, at end of period	$349	$154
Supplemental disclosure of cash flow information:		
Interest paid	$430	$1,016

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

Abraxas Petroleum Corporation
Notes to Condensed Consolidated Financial Statements
(Unaudited)
(tabular amounts in thousands, except per unit data)

Note 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, 2013 filed with the SEC on March 17, 2014. 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, but in the opinion of management, reflect all adjustments necessary for a fair presentation of the financial position and results of operations. Any and all adjustments are of a normal and recurring nature. Although management believes the unaudited interim related disclosures in these condensed consolidated financial statements are adequate to make the information presented not misleading, certain information and footnote disclosures normally included in annual audited consolidated financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been condensed or omitted pursuant to the rules and regulations of the SEC. The results of operations and the cash flows for the period ended March 31, 2014 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, 2013.

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") and a wholly-owned foreign subsidiary, Canadian Abraxas Petroleum, ULC ("Canadian Abraxas").

Canadian Abraxas' assets and liabilities are translated to U.S. dollars at period-end exchange rates. Income and expense items are translated at average rates of exchange prevailing during the period. Translation adjustments are accumulated as a separate component of stockholders' equity.

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 holds 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.

Stock-Based Compensation and Option Plans

Stock Options

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

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

Three Months Ended March 31,	
2014	2013
$306	$362

The following table summarizes the Company's stock option activity for the three months ended March 31, 2014:

	Number of Shares	Weighted Average Option Exercise Price Per Share	Weighted Average Grant Date Fair Value Per Share
Outstanding, December 31, 2013	5,400	$2.77	$1.98
Granted	923	3.15	2.28
Exercised	(59)	2.07	1.31
Canceled	(29)	3.23	2.30
Outstanding, March 31, 2014	6,235	$2.83	$1.99

Additional information related to stock options at March 31, 2014 and December 31, 2013 is as follows:

	March 31, 2014	December 31, 2013
Options exercisable	4,112	3,828

As of March 31, 2014, there was approximately $2.1 million of unamortized compensation expense related to outstanding stock options that will be recognized in 2014 through 2018.

Restricted Stock Awards

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

The following table summarizes the Company's restricted stock activity for the three months ended March 31, 2014:

	Number of Shares	Weighted Average Grant Date Fair Value Per Share
Unvested, December 31, 2013	355	$3.24
Granted	741	3.15
Vested/Released	—	4.88
Forfeited	(8)	3.44
Unvested, March 31, 2014	1,088	$3.18

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

Three Months Ended March 31,	
2014	2013
$133	$112

As of March 31, 2014, there was approximately $2.6 million of unamortized compensation expense relating to outstanding restricted shares that will be recognized in 2014 through 2018.

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 the 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 the unamortized capitalized cost or the cost ceiling. The ceiling cost is calculated as PV-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. We calculate the projected income tax effect using the “short-cut” method for the cost ceiling test calculation. Costs in excess of the cost ceiling are charged to proved property impairment expense. No gain or loss is recognized upon sale or disposition of oil and gas properties, except where the sale or disposition causes a significant change in the relationship between capitalized cost and the estimated quantity of proved reserves. We apply the full cost ceiling test on a quarterly basis on the date of the latest balance sheet presented. At March 31, 2014, our net capitalized costs of oil and gas properties in the United States and Canada did not exceed the cost ceiling of our estimated proved reserves.

Restoration, Removal and Environmental Liabilities

The Company is subject to extensive Federal, provincial, 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 are fixed or reliably determinable.

The Company accounts for asset retirement 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 asset retirement obligation transactions for the three months ended March 31, 2014 and the year ended December 31, 2013:

	March 31, 2014	December 31, 2013
Beginning asset retirement obligation	$9,888	$11,381
New wells placed on production and other	125	222

Deletions related to property disposals and plugging costs	(229)	(2,491)
Accretion expense	144	638
Revisions	(82)	138
Ending asset retirement obligation	$9,846	$9,888

Note 2. Income Taxes

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

For the three months ended March 31, 2014, there was no current or deferred income tax expense or benefit due to loss carryforwards. Valuation allowances have been recorded against such benefits in prior periods.

The Company accounts for uncertain tax positions under the provisions of ASC 740-10. The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. As of March 31, 2014, the Company did not have any accrued interest or penalties related to uncertain tax positions. The tax years 2003 through 2013 remain open to examination by the tax jurisdictions to which the Company is subject.

At December 31, 2013, the Company had $141.9 million of net operating loss carryforwards for U.S. tax purposes and $20.5 million of net operating loss carryforwards for Canadian tax purposes. The U.S. loss carryforward will expire in varying amounts through 2033 and the Canadian loss carryforward will expire in 2033, if not utilized.

Note 3. Long-Term Debt

The following table summarizes the Company's long-term debt:

	March 31, 2014	December 31, 2013
Credit facility	$60,000	$33,000
Rig loan agreement	6,063	6,378
Real estate lien note	4,499	4,554
	70,562	43,932
Less current maturities	(2,158)	(2,142)
	$68,404	$41,790

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 March 31, 2014, $60.0 million was outstanding and $70.0 million was available under the credit facility.

The credit facility has a maximum commitment of $300.0 million and availability is subject to a borrowing base. As of March 31, 2014 we had a borrowing base of $130.0 million and availability of $70.0 million. The borrowing base is determined semi-annually by the lenders based upon our reserve reports, one of which must be prepared by our independent petroleum engineers and one of which may be prepared internally. The amount of the borrowing base is calculated by the lenders based upon their valuation of our proved reserves securing the facility, utilizing these reserve reports, and their own internal decisions. In addition, the lenders, in their sole discretion, are able to make one additional borrowing base redetermination during any six-month period between scheduled redeterminations and we are able to request one redetermination during any six-month period between scheduled redeterminations. The borrowing base will be automatically reduced in connection with any sales of producing properties with a market value of 5% or more of our then-current borrowing base and in connection with any hedge termination which could reduce the collateral value by 5% or more. Our borrowing base can never exceed the $300.0 million maximum commitment amount. Outstanding amounts under the credit facility bear interest at (a) 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) 1.25%—2.25%, depending on the utilization of the borrowing base, or, if we elect LIBOR plus 2.25%—3.25%, depending on the utilization of the borrowing base. At March 31, 2014 the interest rate on the credit facility was 2.65% based on 1-month LIBOR borrowings and the level of utilization.

Subject to earlier termination rights and events of default, the stated maturity date of the credit facility is June 30, 2015. 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.

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 to maintain a debt to EBITDAX ratio as of the last day of each quarter 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 minus all non-cash items of income which were included in determining consolidated net income, 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 March 31, 2014 we were in compliance with all of our debt covenants. As of March 31, 2014, the interest coverage ratio was 14.58 to 1.00, the total debt to EBITDAX ratio was 1.23 to 1.00 and the current ratio was 1.64 to 1.00.

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

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

The credit facility also contains 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 with RBS Asset Finance, Inc. to finance the costs of purchasing and refurbishing an Oilwell 2,000 hp diesel electric drilling rig (the "Collateral"). The rig loan

agreement provided for interim borrowings payable to Raven Drilling until the final amount of the loan was determined.

On February 14, 2012, Raven Drilling finalized the note with respect to the rig loan agreement. The principal amount of the note was $7.0 million and bears interest at 4.26%. Interest only was due for the first 18-months of the note and thereafter, the note amortizes in full over the remaining life of the note. Interest and principal are payable monthly. Subject to earlier prepayment provisions and events of default, the stated maturity date of the note is February 14, 2017. As of March 31, 2014, $6.1 million was outstanding under the rig loan agreement.

Abraxas Petroleum 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

On May 9, 2008, the Company entered into an advancing line of credit in the amount of $5.4 million for the purchase and finish out of a building to serve as its corporate headquarters. This note was refinanced in November 2008. The note was modified on April 4, 2013, reducing the interest to a fixed rate of 4.0%, effective March 13, 2013 and was further modified on July 20, 2013 to extend the maturity date to July 20, 2023. The note is payable in monthly installments of principal and interest of $34,354 based on a twenty-year amortization. Beginning August 20, 2018, the interest rate will adjust to the current bank prime rate plus 1.00% with a maximum rate of 7.25%. The note is secured by a first lien deed of trust on the property and improvements. As of March 31, 2014, $4.5 million was outstanding on the note.

Note 4. Income Per Share

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

	Three Months Ended March 31,	
	2014	2013
Numerator:		
Net income	$4,704	$595
Denominator:		
Denominator for basic income per share - Weighted-average shares	92,566	92,290
Effect of dilutive securities:		
Stock options and restricted stock	1,755	974
Denominator for diluted income per share - Weighted-average shares and assumed conversions	94,321	93,264
Net income per common share – basic	$0.05	$0.01
Net income per common share – diluted	$0.05	$0.01

Note 5. Hedging Program and Derivatives

The derivative instruments we utilize are based on index prices that may and often do differ from the actual oil and gas prices realized in our operations. Management has elected not to apply hedge accounting as prescribed by ASC 815. Accordingly, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period.

The following table sets forth our derivative contracts at March 31, 2014:

	Fixed Price Swap							
	Oil – WTI		Oil - Brent		Oil - LLS		Natural Gas - NYMEX	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (Mcf)	Swap Price (per Mcf)
2014	1,510	$92.75	—	$—	98	$101.26	3,167	$4.06
2015	553	$85.00	494	$97.04	—	$—	1,450	$4.08
2016	948	$84.10	—	$—	—	$—	—	$—
2017	494	$84.18	—	$—	—	$—	—	$—

At March 31, 2014, the aggregate fair value of our commodity derivative contracts was a liability of approximately $4.6 million.

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

Fair Value of Derivative Instruments as of March 31, 2014

	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	$218	Derivatives – current	$2,860
Commodity price derivatives	Derivatives - long-term	547	Derivatives - long-term	2,510
		$765		$5,370

Fair Value of Derivative Instruments as of December 31, 2013

	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	$85	Derivatives – current	$2,728
Commodity price derivatives	Derivatives – long-term	925	Derivatives – long-term	2,274
		$1,010		$5,002

Gains and losses from derivative activities are reflected as "Loss on derivative contracts" in the accompanying condensed consolidated statements of operations.

Note 6. Fair Value

Fair Value Hierarchy—ASC 820-10 establishes a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

- Level 1 – inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.

- Level 2 – inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.

- Level 3 - inputs to the valuation methodology are unobservable and significant to the fair value measurement.

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

performance risk, based on the counter-party's credit risk, could result in an adjustment of the carrying value of the derivative instrument. The following tables set forth information about the Company's assets and liabilities measured at fair value on a recurring basis as of March 31, 2014 and December 31, 2013, and indicate the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value (in thousands):

	Significant Other Observable Inputs (Level 2)	Balance March 31, 2014
Assets:		
Fixed Price Derivative contracts	$765	$765
Total Assets	$765	$765
Liabilities:		
Fixed Price Derivative contracts	$5,370	$5,370
Total Liabilities	$5,370	$5,370

	Significant Other Observable Inputs (Level 2)	Balance December 31, 2013
Assets:		
Fixed Price Derivative contracts	$1,010	$1,010
Total Assets	$1,010	$1,010
Liabilities:		
Fixed Price Derivative contracts	$5,002	$5,002
Total Liabilities	$5,002	$5,002

The Company's derivative contracts consist of NYMEX-based fixed price commodity swaps. The NYMEX-based fixed price derivative contracts 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 these derivative contracts is 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.

Other Financial Instruments

The carrying amounts of our cash, cash equivalents, restricted cash, accounts receivable, accounts payable, and accrued liabilities 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.

Note 7. Business Segments

The following tables provide the Company’s geographic operating segment data for the three months ended March 31, 2014 and 2013:

	Three months ended March 31, 2014			
	U.S.	Canada	Corporate	Total
Revenues:				
Oil and gas production revenues	$25,475	$375	$—	$25,850
Other	—	—	43	43
	25,475	375	43	25,893
Expenses:				
Lease operating expenses	5,645	247	—	5,892
Production taxes	2,204	—	—	2,204
Depreciation, depletion and amortization	7,437	136	62	7,635
General and administrative	509	348	1,966	2,823
Net interest	138	6	464	608
Amortization of deferred financing fees	—	—	348	348
Loss on derivative contracts - Realized	—	—	734	734
Loss on derivative contracts - Unrealized	—	—	945	945
Net income (loss)	$9,542	$(362)	$(4,476)	$4,704

	Three months ended March 31, 2013			
	U.S.	Canada	Corporate	Total
Revenues:				
Oil and gas production revenues	$20,558	$605	$—	$21,163
Other	—	—	33	33
	20,558	605	33	21,196
Expenses:				
Lease operating expenses	5,804	658	—	6,462
Production taxes	1,927	—	—	1,927
Depreciation, depletion and amortization	6,214	233	62	6,509
General and administrative	475	155	1,900	2,530
Net interest	166	6	1,035	1,207
Amortization of deferred financing fees	—	—	333	333
Loss on derivative contracts - Realized	—	—	925	925
Loss on derivative contracts - Unrealized	—	—	621	621
Other			87	87
Net income (loss)	$5,972	$(447)	$(4,930)	$595

The following table provides the Company's geographic asset data as of March 31, 2014 and December 31, 2013:

Segment Assets:	March 31, 2014	December 31, 2013
United States	$228,072	$213,212
Canada	1,302	1,640
Corporate	8,140	8,798
	$237,514	$223,650

Note 8. Contingencies – Litigation

From time to time, the Company is involved in litigation relating to claims arising out of its operations in the normal course of business. At March 31, 2014, the Company was not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on its operations.

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, 2013 filed with the SEC on March 17, 2014.

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, 2013.

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 and Canada. Historically, we have grown through the acquisition and subsequent development and exploitation of producing properties, principally through the redevelopment of old fields utilizing new technologies such as modern log analysis and reservoir modeling techniques as well as 3-D seismic surveys and horizontal drilling. As a result of these activities, we believe that we have a number of development opportunities on our properties. In addition, we intend to expand upon our development activities with complementary 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

While we have attained positive net income in two of the last five years, there can be no assurance that operating income and net earnings will be achieved in future periods. Our financial results depend upon many factors which significantly affect our results of operations including the following:

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

Commodity Prices and Hedging Activities

The results of our operations are highly dependent upon the prices received for our production. The prices we receive 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 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 production are dependent upon numerous factors beyond our control. Significant declines in commodity prices could have a material adverse effect on our financial condition, results of operations, cash flows and quantities of reserves recoverable on an economic basis.

During the three months ended March 31, 2014, the New York Mercantile (NYMEX) future price for oil averaged $98.61 per barrel as compared to $94.36 per barrel during the three months ended March 31, 2013. NYMEX future spot prices for gas averaged $4.72 per MMBtu for the three months ended March 31, 2014 compared to $3.48 for the same period of 2013. Prices closed on March 31, 2014 at $101.58 per Bbl of oil and $4.37 per MMBtu of gas,

compared to closing on March 31, 2013 at $97.23 per Bbl of oil and $3.48 per MMBtu of gas. The realized prices that we receive for our production differ from NYMEX futures and spot market prices, principally due to:

- basis differentials which are dependent on actual delivery location;
- adjustments for BTU content;
- quality of the hydrocarbons; and

•gathering, processing and transportation costs.

The following table sets forth our average differentials for the three months ended March 31, 2014 and 2013:

	Oil - NYMEX		Gas - NYMEX	
	Three months ended March 31,			
	2014	2013	2014	2013
Average realized price (1)	$90.18	$90.62	$5.03	$3.02
Average NYMEX price	98.61	94.36	4.72	3.48
Differential	$(8.43)	$(3.74)	$0.31	$(0.46)

(1)Excludes the impact of derivative activities

Increases in the differential between the NYMEX price and the realized price we receive have in the past, and could in the future, significantly reduce our revenues and cash flow from operations. The decrease in the gas differential was primarily due to higher realized prices for Bakken gas due to its high BTU content. Our average price differentials relative to WTI increased due to increases in U.S. production growth constraining available pipeline takeaway and refining capacity in the regions in which we operate.

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. By removing a significant portion of price volatility on our future 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 on the portion of the production that has been hedged. We have sustained and, in the future, will sustain realized and unrealized 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 recognize realized and unrealized gains on our commodity derivative contracts. For the three months ended March 31, 2014, we recognized a realized loss of $0.7 million and an unrealized loss of $0.9 million on our commodity swaps. In the three months ended March 31, 2013, we recognized an unrealized loss $0.6 million and a realized loss of $0.9 million on our commodity swaps. We have not designated any of these derivative contracts as a hedge as prescribed by applicable accounting rules.

The following table sets forth our derivative contracts at March 31, 2014:

	Fixed Price Swap							
	Oil – WTI		Oil - Brent		Oil - LLS		Natural Gas - NYMEX	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (Mcf)	Swap Price (per Mcf)
2014	1,510	$92.75	—	$—	98	$101.26	3,167	$4.06
2015	553	$85.00	494	$97.04	—	$—	1,450	$4.08
2016	948	$84.10	—	$—	—	$—	—	$—
2017	494	$84.18	—	$—	—	$—	—	$—

At March 31, 2014, the aggregate fair value of our oil and gas derivative contracts was a liability of approximately $4.6 million.

Production Volumes

Our proved reserves will decline as oil and gas are produced, unless we find, acquire or develop additional properties containing proved reserves or conduct successful exploration and development activities in a timely manner. Based on the reserve information set forth in our reserve estimates as of December 31, 2013, the average annual estimated decline rate for our net proved developed producing reserves is 9% during the first five years, 9% in the next five years, and approximately 9% thereafter. These rates of decline are estimates and actual production declines could be materially higher. While we have had some success in finding, acquiring and developing additional reserves, we have not always been able to fully replace the production volumes lost from

natural field declines and prior property sales. Our ability to acquire or find additional reserves will be dependent, in part, upon the amount of available funds for acquisition, exploration and development projects.

We had capital expenditures of $36.7 million during the three months ended March 31, 2014. We have a capital expenditure budget for 2014 of $125.0 million. Approximately 94% of the 2014 budget will be spent on unconventional horizontal oil wells in the Bakken/Three Forks and Eagle Ford plays, with the remainder being utilized for leasehold acquisition. The 2014 capital expenditure budget is subject to change depending upon a number of factors, including the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the availability of sufficient capital resources, the results of our exploitation efforts, and our ability to obtain permits for drilling locations.

Availability of Capital

As described more fully under “Liquidity and Capital Resources” below, our sources of capital are cash flow from operating activities, borrowings under our credit facility, cash on hand, proceeds from the sale of properties, and if an appropriate opportunity presents itself, the sale of debt or equity securities, although we may not be able to complete any financing on terms acceptable to us, if at all. As of March 31, 2014, we had $70.0 million of availability under our credit facility.

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, 2013, we operated properties accounting for approximately 94% 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, 2013, we drilled or participated in 142 gross (40.0 net) wells of which 96% were commercially productive.

Our future oil and gas production, and therefore our success, is highly dependent upon our ability to find, acquire and develop additional reserves that are profitable to produce. The rate of production from our oil and gas properties and our proved reserves will decline as our reserves are produced unless we acquire additional properties containing proved reserves, conduct successful development and exploration activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves. We cannot assure you that our exploration and development activities will result in increases in our proved reserves. If our proved reserves decline in the future, our production may also decline and, consequently, our cash flow from operations and the amount that we are able to borrow under our credit facility may also decline. In addition, approximately 56% of our estimated proved reserves at December 31, 2013 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, in which case our results of operations and financial condition could be adversely affected.

Operational Update

In the following discussion, production rates do not include the impact of NGL production and shrinkage from processing including the flaring of gas. The following provides an overview of our present activities by region:

Eagle Ford

At Abraxas' Jourdanton prospect in Atascosa County, Texas, the Snake Eyes 1H averaged 531 boepd (493 barrels of oil per day, 232 mcf of natural gas per day) over the well's first 23 full days of production flowing naturally. After loading up after 23 days, the well was placed on sub-pump. Since being placed on sub-pump, the well produced 729 boepd (703 barrels of oil per day, 158 mcf of natural gas per day) in its first full production day. Abraxas recently completed the Spanish Eyes 1H with a 19 stage completion. The well has been flowing to sales for approximately 19 days and is expected to be placed on sub-pump this week. Abraxas also recently completed the Eagle Eyes 1H with an 18 stage completion and the well just began flowback. Abraxas owns a 100% working interest across the Jourdanton prospect. Total acreage at Jourdanton now consists of approximately 7,142 net acres.

At Abraxas' Cave prospect, in McMullen County, Texas, the company shut in the Dutch 2H on April 14 to begin drilling operations on the Dutch 1H. The Dutch 1H is currently drilling at 16,583 feet and is expected to be fracture stimulated and turned to sales in mid-June. Abraxas holds a 100% working interest in the Dutch 1H and 2H.

At Abraxas' Dilworth East prospect, in McMullen County, Texas the company plans to complete the R. Henry 2H with a 19 stage fracture stimulation in late May. The well is currently anticipated to be turned over to sales in early June when gas takeaway is available at the lease. Abraxas holds a 100% working interest in the R. Henry 2H.

Williston Basin

In McKenzie County, North Dakota, the Jore 1H, 2H and 4H are currently being fracture stimulated. On the Ravin West pad, Abraxas recently reached TD on the lateral of the Ravin 4H at 20,754 feet. After casing the lateral on the Ravin 4H, the company will drill the laterals of the Ravin 5H, Ravin 6H and Ravin 7H. Abraxas owns a working interest of approximately 76% and 51% in the Jore and Ravin West pads, respectively.

Results of Operations

The following table sets forth certain of our consolidated operating data for the periods presented:

	Three Months Ended March 31,	
	2014	2013
Operating revenue: (1)		
Oil sales	$20,935	$17,184
Gas sales	3,250	2,852
NGL sales	1,665	1,127
Other	43	33
	$25,893	$21,196
Operating income	7,339	3,768
Oil sales (MBbl)	232	190
Gas sales (MMcf)	646	945
NGL sales (MBbl)	37	32
Boe sales	377	379
Average oil sales price (per Bbl) (1)	$90.18	$90.62
Average gas sales price (per Mcf) (1)	$5.03	$3.02
Average NGL sales price (per Bbl)	$44.85	$34.88
Average oil equivalent price (Boe)	$68.57	$55.77

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

Comparison of Three Months Ended March 31, 2014 to Three Months Ended March 31, 2013
Operating Revenue. During the three months ended March 31, 2014 operating revenue increased to $25.9 million from $21.2 million for the same period of 2013. The increase in revenue was primarily due to higher oil and NGL production as well as higher realized commodity prices. Increased oil and NGL sales volumes contributed $4.1 million to operating revenue for the three months ended March 31, 2014, partially offset by lower gas sales volumes. Decreased oil prices had a negative impact of $0.08 million and increased NGL prices contributed $0.3 million. Lower gas sales volumes negatively impacted revenue by $1.5 million. Increased gas prices contributed $1.9 million to revenue.

Oil sales volumes increased to 232 MBbl during the three months ended March 31, 2014 from 190 MBbl for the same period of 2013. The increase in oil sales was due to new wells brought on line, offset by natural field declines and sales of non-core properties. New wells brought on production contributed 133 MBbl for the three months ended March 31, 2014. Properties sold during 2013 contributed 76.7 MBbl during the first quarter of 2013. Gas sales volumes decreased to 646 MMcf for the three months ended March 31, 2014 from 945 MMcf for the same period of 2013. The decrease in gas production was due to natural field declines; the timing of new wells being brought on line and property sales, as well as our emphasis on drilling oil wells as opposed to gas wells. New wells brought on production contributed 75.9 MMcf for the three months ended March 31, 2014. Properties sold during 2013 contributed 115.0 MMcf in the first quarter of 2013. NGL sales volumes increased to 37 MBbl for

the three months ended March 31, 2014 from 32 MBbl for the same period of 2013. The increase in NGL sales was primarily due to increased gas production in West Texas and North Dakota that has a higher NGL content than our historical gas production.

Lease Operating Expenses ("LOE"). LOE for the three months ended March 31, 2014 decreased to $5.9 million from $6.5 million for the same period in 2013. The decrease in LOE was partially due to the disposition of high cost properties during 2013. LOE per Boe for the three months ended March 31, 2014 was $15.63 compared to $17.03 for the same period of 2013. The decrease per Boe was due to lower costs and higher sales volumes for the three months ended March 31, 2014 as compared to the same period of 2013.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the three months ended March 31, 2014 increased to $2.2 million from $1.9 million for the same period of 2013. The increase was primarily due to higher realized commodity prices in the quarter ended March 31, 2014 as compared to the same period of 2013.

General and Administrative ("G&A") Expenses. G&A expenses, excluding stock-based compensation, for the three months ended March 31, 2014 increased to $2.4 million as compared to $2.1 million for the same period of 2013. The increase in G&A expense was primarily due to an increase in personnel and the corresponding increase in salary expense for the first quarter of 2014. G&A expense per Boe, excluding stock-based compensation, was $6.32 for the quarter ended March 31, 2014 compared to $5.42 for the same period of 2013. The increase per Boe was due to higher costs.

Stock-Based Compensation. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options vesting period. In addition to options, restricted shares of the Company's common stock have been granted and are valued at the date of grant and expense is recognized over their vesting period. For the three months ended March 31, 2014 stock-based compensation was $0.4 million compared to $0.5 million in 2013.

Depreciation, Depletion and Amortization ("DD&A") Expenses. DD&A expense for the three months ended March 31, 2014 increased to $7.6 million from $6.5 million for the same period of 2013. The increase was primarily the result of an increase in future development costs in our December 31, 2013 reserve report. DD&A expense per Boe for the three months ended March 31, 2014 was $20.25 compared to $17.15 in 2013.

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 March 31, 2014, our net capitalized costs of oil and gas properties in the United States and Canada did not exceed the present value of our estimated proved reserves.

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

Interest Expense. Interest expense for the three months ended March 31, 2014 decreased to $0.6 million from $1.2 million for the same period of 2013. The decrease was primarily due to lower debt levels in 2014 as compared to the same period of 2013.

(Gain) loss 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 contracts do not qualify for hedge accounting as prescribed by ASC 815; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. Our derivative contracts consist of commodity swaps. The estimated value of our commodity derivative contracts was a liability of approximately $4.6 million as of March 31, 2014. 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 three months ended March 31, 2014, we realized a loss on our commodity derivative contracts of $0.7 million and we incurred an unrealized loss of

$0.9 million on our commodity derivative contracts. For the three months ended March 31, 2013, we realized a loss on our commodity derivative contracts of $0.9 million and we incurred an unrealized loss of $0.6 million on our commodity derivative contracts.

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 an opportunity presents itself, the sale of debt or equity securities, although we may not be able to complete any financings on terms acceptable to us, if at all.

Capital expenditures. Capital expenditures during the three months ended March 31, 2014 were $36.7 million compared to $17.8 million during the same period of 2013.

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

	Three Months Ended March 31,	
	2014	2013
Expenditure category:		
Development and land	$35,802	$17,410
Facilities and other	917	363
Total	$36,719	$17,773

During the three months ended March 31, 2014, capital expenditures were primarily for development of our existing oil and gas properties. During the three months ended March 31, 2013 capital expenditures were primarily for development of our existing oil and gas properties and the completion of the refurbishment of our drilling rig. We anticipate making capital expenditures in 2014 of $125.0 million. The 2014 capital expenditure budget is subject to change depending upon a number of factors, including the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the availability of sufficient capital resources, and our ability to obtain permits for drilling locations. Our capital expenditures could also include expenditures for the acquisition of producing properties, if such opportunities arise. Additionally, the level of capital expenditures will vary during future periods depending on economic and industry conditions and commodity prices. Should the prices of oil and gas decline and if our costs of operations increase or if our production volumes decrease, our cash flows will decrease which may result in a reduction of the

capital expenditure budget. If we decrease our capital expenditure budget, we may not be able to offset oil and gas production decreases caused by natural field declines.

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

	Three Months Ended March 31,	
	2014	2013
Net cash provided by operating activities	$2,424	$9,913
Net cash used in investing activities	(33,937)	(17,773)
Net cash provided by financing activities	26,656	5,953
Total	$(4,857)	$(1,907)

Operating activities during the three months ended March 31, 2014 provided $2.4 million of cash compared to providing $9.9 million in the same period of 2013. For the three months ended March 31, 2014 and 2013, net income plus non-cash expense items accounted for most of these funds. Investing activities used $33.9 million, net of proceeds from the sale of oil and gas properties, during the three months ended March 31, 2014 compared to using $17.8 million for the same period of 2013. Funds used during the three months ended March 31, 2014 were primarily expenditures for the development of our existing properties and leasehold acquisitions. Funds used during the three months ended March 31, 2013 were also primarily expenditures for the development of our existing properties. Financing activities provided $26.7 million for the three months ended March 31, 2014 compared to providing $6.0 million for the same period in 2013. Funds provided during the three months ended March 31, 2014 and 2013 were primarily borrowings under our credit facility.

Future Capital Resources. Our principal sources of capital going forward are cash flows from operations, borrowings under our credit facility, cash on hand, proceeds from the sale of properties, and if an opportunity presents itself, the sale of debt or equity securities, although we may not be able to complete financing on terms acceptable to us, if at all.

Cash from operating activities is dependent upon commodity prices and production volumes. A decrease 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 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 56% of our total estimated proved reserves at December 31, 2013 were classified as undeveloped.

We have in the past, and may, in the future, sell producing properties. Beginning in the third quarter of 2012 and continuing through the first quarter of 2014, we have sold certain non-core assets for combined net proceeds of approximately $151.7 million. The net proceeds were used to repay outstanding indebtedness under our credit facility.

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

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

Below is a schedule of the future payments that we are obligated to make based on agreements in place as of March 31, 2014:

	Payments due in twelve month periods ending:				
		March 31,			
	Total	2015	2016-2017	2018-2019	Thereafter
Long-term debt (1)	$70,562	$2,158	$64,602	$518	$3,284
Interest on long-term debt (2)	3,808	2,000	927	306	575
Lease obligations (3)	55	37	18	—	—
Total	$74,425	$4,195	$65,547	$824	$3,859

(1) These amounts represent the balances outstanding under our credit facility, the rig loan agreement and the real estate lien note. These repayments 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 September 30, 2014, office space in Lusk, Wyoming, which expires on December 31, 2016 and office space in Denver, Colorado, which expires December 31, 2014.

We maintain a reserve for costs associated with the retirement of tangible long-lived assets. At March 31, 2014, our reserve for these obligations totaled $9.8 million for which no contractual commitment exists. For additional information relating to this obligation, see Note 1 of the Notes to Condensed Consolidated Financial Statements.

Off-Balance Sheet Arrangements. At March 31, 2014, we had no existing off-balance sheet arrangements, as defined under SEC regulations, which have or are reasonably likely to have a current or future effect on our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Contingencies. From time to time, we are involved in litigation relating to claims arising out of our operations in the normal course of business. At March 31, 2014, we were not engaged in any legal proceedings that were expected, individually or in the aggregate, to have a material adverse effect on the Company.

Other Obligations. We make and will continue to make substantial capital expenditures for the acquisition, development, exploration and production of oil and gas. In the past, we have funded our operations and capital expenditures primarily through cash flow from operations, sales of properties, sales of production payments and borrowings under our credit facilities and other sources. Given our high degree of operating control, the timing and incurrence of capital expenditures is largely within our discretion.

Long-Term Indebtedness

The following table summarizes the Company’s long-term debt:

	March 31, 2014	December 31, 2013
Credit facility	$60,000	$33,000
Rig loan agreement	6,063	6,378
Real estate lien note	4,499	4,554
	70,562	43,932
Less current maturities	(2,158)	(2,142)
	$68,404	$41,790

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 March 31, 2014, $60.0 million was outstanding and $70.0 million was available under the credit facility.

The credit facility has a maximum commitment of $300.0 million and availability is subject to a borrowing base. As of March 31, 2014 we had a borrowing base of $130.0 million. The borrowing base is determined semi-annually by the lenders based upon our reserve reports, one of which must be prepared by our independent petroleum engineers and one of which may be prepared internally. The amount of the borrowing base is calculated by the lenders based

upon their valuation of our Proved reserves securing the facility utilizing these reserve reports and their own internal decisions. In addition, the lenders, in their sole discretion, are able to make one additional borrowing base redetermination during any six-month period between scheduled redeterminations and we are able to request one redetermination during any six-month period between scheduled redeterminations. The borrowing base will be automatically reduced in connection with any sales of producing properties with a market value of 5% or more of our then-current borrowing base and in connection with any hedge termination which could reduce the collateral value by 5% or more. Our borrowing base can never exceed the $300.0 million maximum commitment amount. Outstanding amounts under the credit facility bear interest at (a) 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) 1.25—2.25%, depending on the utilization of the borrowing base, or, if we elect LIBOR plus 2.25%—3.25%, depending on the utilization of the borrowing base. At March 31, 2014, the interest rate on the credit facility was 2.65% based on 1-month LIBOR borrowings and level of utilization.

Subject to earlier termination rights and events of default, the stated maturity date of the credit facility is June 30, 2015. 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.

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 to maintain a total debt to EBITDAX ratio as of the last day of each quarter 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 minus all non-cash items of income which were included in determining consolidated net income, 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 rig loan and obligations with respect to surety bonds and derivative contracts.

At March 31, 2014, we were in compliance with all of our debt covenants. As of March 31, 2014, the interest coverage ratio was 14.58 to 1.00, the total debt to EBITDAX ratio was 1.23 to 1.00 and the current ratio was 1.64 to 1.00.

The credit facility contains a number of covenants that, among other things, restrict our ability to:
•incur or guarantee additional indebtedness;
•transfer or sell assets;
•create liens on assets;
•engage in transactions with affiliates other than on an "arm's length" basis;
•make any change in the principal nature of our business; and
•permit a change of control.

The credit facility also contains 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 with RBS Asset Finance, Inc. to finance the costs of purchasing and refurbishing an Oilwell 2000 hp diesel electric drilling rig (the “Collateral”). The rig loan agreement provided for interim borrowings payable to Raven Drilling until the final amount of the loan was determined.

On February 14, 2012, Raven Drilling finalized the note with respect to the rig loan agreement. The principal amount of the note was $7.0 million and bears interest at 4.26%. Interest only was due for the first 18-months of the note and thereafter, the

note amortizes in full over the remaining life of the note. Interest and principal, when required, is payable monthly. Subject to earlier prepayment provisions and events of default, the stated maturity date of the note is February 14, 2017. As of March 31, 2014, $6.1 million was outstanding under the rig loan agreement.

Abraxas Petroleum 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

On May 9, 2008, the Company entered into an advancing line of credit in the amount of $5.4 million for the purchase and finish out of a building to serve as its corporate headquarters. This note was refinanced in November 2008. The note was modified on April 4, 2013, reducing the interest to a fixed rate of 4.0%, effective March 13, 2013 and was further modified on July 20, 2013 to extend the maturity date to July 20, 2023. The note is payable in monthly installments of $34,354 based on a twenty year amortization. Beginning August 20, 2018, the interest rate will adjust to the current bank prime rate plus 1.00% with a maximum rate of 7.25%. The note is secured by a first lien deed of trust on the property and improvements. As of March 31, 2014, $4.5 million was 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.

The following table sets forth our derivative contract position as of March 31, 2014:

	Fixed Price Swap							
	Oil – WTI		Oil - Brent		Oil - LLS		Natural Gas - NYMEX	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (Mcf)	Swap Price (per Mcf)
2014	1,510	$92.75	—	$—	98	$101.26	3,167	$4.06
2015	553	$85.00	494	$97.04	—	$—	1,450	$4.08
2016	948	$84.10	—	$—	—	$—	—	$—
2017	494	$84.18	—	$—	—	$—	—	$—

By removing a significant 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, realized and unrealized 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 realized and unrealized gains on our commodity derivative contracts. If the disparity between our contract prices and market prices continues, we will sustain realized and unrealized gains or losses on our derivative contracts. While unrealized gains and losses do not impact our cash flow from operations, realized gains and losses 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. In addition, the borrowings under our credit facility bear interest at floating rates. 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.

See "—Quantitative and Qualitative Disclosures about Market Risk—Derivative Instruments" for further information.

Net Operating Loss Carryforwards.

At December 31, 2013, we had, subject to the limitation discussed below, $141.9 million of net operating loss carryforwards for U.S. tax purposes and $20.5 million for Canadian tax purposes. The U.S. loss carryforwards will expire through 2033 and the Canadian carryforward will expire in 2033, if not utilized.

Uncertainties exist as to the future utilization of the operating loss carryforwards under the criteria set forth under ASC 740-10 “Income Taxes”. Therefore, we have established a valuation allowance of $75.6 million for deferred tax assets at December 31, 2013.

We account for uncertain tax positions under the provisions of ASC 740-10. ASC 740-10 did not have any effect on the Company’s financial position or results of operations for the three months ended year ended March 31, 2014. The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. As of March 31, 2014 the Company did not have any accrued interest or penalties related to uncertain tax positions. The tax years from 2003 through 2013 remain open to examination by the tax jurisdictions to which the Company is subject.

Item 3. Quantitative and Qualitative Disclosures about Market Risk.

Commodity Price Risk

As an independent oil and gas producer, our revenue, cash flow from operations, other income and profitability, reserve values, access to capital and future rate of growth are substantially dependent upon the prevailing prices of oil and gas. Declines in commodity prices will adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower commodity prices may reduce the amount of oil and gas that we can produce economically. Prevailing prices for such commodities are subject to wide fluctuation in response to relatively minor changes in supply and demand and a variety of additional factors beyond our control, such as global, political and economic conditions. Historically, prices received for our oil and gas production have been volatile and unpredictable, and such volatility is expected to continue. Most of our production is sold at market prices. Generally, if the commodity indexes fall, the price that we receive for our production will also decline. Therefore, the amount of revenue that we realize is partially determined by factors beyond our control. Assuming the production levels we attained during the three months ended March 31, 2014, a 10% decline in oil and gas prices would have reduced our operating revenue, cash flow and net income by approximately $2.6 million; however, due to the derivative contracts that we have in place, it is unlikely that a 10% decline in commodity prices from their current levels would significantly impact our operating revenue, cash flow and net income.

Derivative Instrument Sensitivity

We account for our derivative contracts in accordance with ASC 815. The derivative instruments we utilize are based on index prices that may and often do differ from the actual oil and gas prices realized in our operations. Management has elected not to apply hedge accounting as prescribed by ASC 815; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period.

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For the three months ended March 31, 2014, we recognized a realized loss of $0.7 million and an unrealized gain of $0.9 million on our commodity derivative contracts.

Interest Rate Risk

We are subject to interest rate risk associated with borrowings under our credit facility. As of March 31, 2014, we had $60.0 million of outstanding indebtedness under our credit facility. Outstanding amounts under the credit facility bear interest 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) 1.25%—2.25%, depending on the utilization of the borrowing base, or, if we elect, LIBOR plus 2.25%—3.25%, depending on the utilization of the borrowing base. At March 31, 2014, the interest rate on the credit facility was 2.65%. For every percentage point that the LIBOR rate rises, our interest expense would increase by approximately $0.6 million on an annual basis, based on our outstanding indebtedness as of March 31, 2014.

Item 4. Controls and Procedures.

As of the end of the period covered by this report, our Chief Executive Officer and Chief Financial Officer carried out an evaluation of the effectiveness of Abraxas' "disclosure controls and procedures" (as defined in the Securities

Exchange Act of 1934 Rules 13a-15(e)and 15d-15(e)) and concluded that the disclosure controls and procedures were effective.

There were no changes in our internal controls over financial reporting during the three months ended March 31, 2014 covered by this report that could materially affect, or are reasonably likely to materially affect, our financial reporting.

ABRAXAS PETROLEUM CORPORATION

PART II
OTHER INFORMATION

Item 1. Legal Proceedings.

From time to time, the Company is involved in litigation relating to claims arising out of its operations in the normal course of business. At March 31, 2014, 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 operations.

Item 1A. Risk Factors.

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, “Item 1A. Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2013, 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

ABRAXAS PETROLEUM CORPORATION

SIGNATURES

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

Date: May 9, 2014	By: /s/Robert L.G. Watson ROBERT L.G. WATSON, President and Principal Executive Officer
Date: May 9, 2014	By: /s/Geoffrey R. King GEOFFREY R. KING, Vice President and Principal Financial Officer
Date: May 9, 2014	By: /s/G. William Krog, Jr. G. WILLIAM KROG, JR., Principal Accounting Officer