ABRAXAS PETROLEUM CORP
Form 10-Q
May 10, 2012

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

FORM 10-Q

(Mark One)
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2012

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 x 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 x No ¨

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

Large accelerated filer 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 x

The number of shares of the issuer's common stock outstanding as of May 4, 2012 was 92,332,057

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:

- our success in development, exploitation and exploration activities;
- our ability to procure services and equipment for our drilling and completion activities;
- the prices we receive for our production and the effectiveness of our hedging activities;
- our ability to make planned capital expenditures;
- declines in our production of oil and gas;
- the availability of capital;
- political and economic conditions in oil producing countries, especially those in the Middle East;
- price and availability of alternative fuels;
- our restrictive debt covenants;
- 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 equivalents are determined using the ratio of six Mcf of gas to one barrel of oil, condensate or natural gas liquids. One Mcf of gas at 1,000 British Thermal Units ("BTU") is equivalent to one MMBtu. 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.

“Boe” – barrels of oil equivalent.

“MBbl” – thousand barrels.

“MBoe” – thousand barrels of oil equivalent.

“Mcf” – thousand cubic feet of gas.

"MMBoe" – million barrels of oil equivalent.

"MMBtu" – million BTU of gas.

"MMcf" – million cubic feet of gas.

"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 well" 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 well.

"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 describe 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” 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 Codifications (“ASC”) 932, “Disclosures About Oil and Gas Producing Activities.”

ABRAXAS PETROLEUM CORPORATION
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PART I
FINANCIAL INFORMATION

Item 1. Financial Statements

Abraxas Petroleum Corporation
Condensed Consolidated Balance Sheets
(in thousands)

	March 31, 2012 (Unaudited)	December 31, 2011
Assets		
Current assets:		
Cash and cash equivalents	$—	$—
Accounts receivable, net:		
Joint owners	2,051	3,354
Oil and gas production	11,075	8,897
Other	303	655
	13,429	12,906
Derivative asset – current	5,091	11,416
Other current assets	483	391
Total current assets	19,003	24,713
Property and equipment:		
Oil and gas properties, full cost method of accounting:		
Proved	513,461	490,908
Unproved properties excluded from depletion	1,927	1,100
Other property and equipment	37,140	33,783
Total	552,528	525,791
Less accumulated depreciation, depletion, and amortization	(351,214)	(346,239)
Total property and equipment – net	201,314	179,552
Investment in joint venture	26,998	26,215
Deferred financing fees, net	3,532	3,490
Derivative asset – long-term	232	6,412
Other assets	773	768
Total assets	$251,852	$241,150

See accompanying notes to condensed consolidated financial statements (unaudited)

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

	March 31, 2012 (Unaudited)	December 31, 2011
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$27,542	$21,373
Oil and gas production payable	7,237	5,835
Accrued interest	162	209
Other accrued expenses	732	284
Derivative liability – current	11,622	11,640
Current maturities of long-term debt	184	181
Total current liabilities	47,479	39,522
Long-term debt, excluding current maturities	126,711	126,258
Derivative liability – long-term	4,696	4,307
Future site restoration	8,681	8,412
Total liabilities	187,567	178,499
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; 92,328,057 and 92,261,057 issued and outstanding	923	923
Additional paid-in capital	249,016	248,480
Accumulated deficit	(185,648)	(186,465)
Accumulated other comprehensive loss	(6)	(287)
Total stockholders' equity	64,285	62,651
Total liabilities and stockholders' equity	$251,852	$241,150

See accompanying notes to condensed consolidated financial statements (unaudited)

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

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
Revenue:		
Oil and gas production revenues	$16,379	$13,847
Other	14	1
	16,393	13,848
Operating costs and expenses:		
Lease operating expenses	5,934	4,015
Production taxes	1,496	1,254
Depreciation, depletion, and amortization	4,838	3,430
General and administrative (including stock-based compensation of $477 and $363, respectively)	1,901	2,646
	14,169	11,345
Operating income	2,224	2,503
Other (income) expense:		
Interest income	(1)	(2)
Interest expense	1,195	1,605
Amortization of deferred financing fees	30	500
Loss on derivative contracts - realized	48	115
Loss on derivative contracts – unrealized	876	10,978
Equity in (gain) of joint venture	(783)	(749)
Other	42	75
	1,407	12,522
Net income (loss)	$817	$(10,019)
Net income (loss) per common share – basic	$0.01	$(0.12)
Net income (loss) per common share – diluted	$0.01	$(0.12)

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, 2012	2011
Consolidated net income (loss)	$817	$(10,019)
Other comprehensive income (loss):		
Change in unrealized value of investments	(4)	17
Foreign currency translation adjustment	285	120
Other comprehensive income	281	137
Comprehensive income (loss)	$1,098	$(9,882)

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, 2012	Three Months Ended March 31, 2011
Operating Activities		
Net income (loss)	$817	$(10,019)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Equity in gain of joint venture	(783)	(749)
Change in derivative fair value	512	10,664
Monetization of derivative contracts	12,364	—
Depreciation, depletion, and amortization	4,838	3,430
Amortization of deferred financing fees	30	500
Accretion of future site restoration	116	109
Stock-based compensation	477	363
Changes in operating assets and liabilities:		
Accounts receivable	(506)	87
Other	(101)	150
Accounts payable and accrued expenses	8,024	(9,463)
Net cash provided by (used in) operating activities	25,788	(4,928)
Investing Activities		
Capital expenditures, including purchases and development of properties	(26,126)	(9,765)
Proceeds from the sale of oil and gas properties	—	8,457
Net cash used in investing activities	(26,126)	(1,308)
Financing Activities		
Proceeds from long-term borrowings	4,500	2,000
Payments on long-term borrowings	(4,044)	(57,040)
Deferred financing fees	(72)	(13)
Proceeds from issuance of common stock	—	62,113
Exercise of stock options	59	—
Other	(105)	36
Net cash provided by financing activities	338	7,096
Increase in cash	—	860
Cash and equivalents, at beginning of period	—	99
Cash and equivalents, at end of period	$—	$959
Supplemental disclosure of cash flow information:		
Interest paid	$1,126	$1,742

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 share 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, 2011 filed with the SEC on March 15, 2012. 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 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 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, 2012 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, 2011.

Consolidation Principles

The terms “Abraxas,” “Abraxas Petroleum,” “we,” “us,” “our” or the “Company” refer to Abraxas Petroleum Corporation ar 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, Option Plans and Warrants

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, 2012	Three Months Ended March 31, 2011
$ 346	$ 267

The following table summarizes the Company’s stock option activity for the three months ended March 31, 2012:

	Number of Shares	Weighted Average Option Exercise Price Per Share	Weighted Average Grant Date Fair Value Per Share	Aggregate Intrinsic Value
Outstanding, December 31, 2011	4,756	$ 2.61	$ 1.85	$ 8,214
Granted	295	$ 3.74	$ 2.76	814
Exercised	(67)	$ 0.89	$ 0.43	(29)
Outstanding, March 31, 2012	4,984	$ 2.70	$ 1.81	$ 8,999

The following table shows the weighted average assumptions used in the Black-Scholes calculation of the fair value of stock option grants for the three months ended March 31, 2012:

Expected dividend yield	0	%
Volatility	80.12	%
Risk free interest rate	1.48	%
Expected life	7.37	Years
Fair value of options granted (in thousands)	$814	
Weighted average grant date fair value per share of options granted	$2.76	

Additional information related to stock options at March 31, 2012 and December 31, 2011 is as follows:

	March 31, 2012	December 31, 2011
Options exercisable	2,964	2,512

As of March 31, 2012, there was approximately $3.5 million of unamortized compensation expense related to outstanding stock options that will be recognized in 2012 through 2016.

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, 2012:

	Number of Shares	Weighted Average Grant Date Fair Value Per Share
Unvested, December 31, 2011	630	$3.03
Granted	—	—
Vested/Released	(107)	1.83
Forfeited	—	—
Unvested, March 31, 2012	523	$3.28

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

Three Months Ended March 31,	
2012	2011
$ 131	$ 96

As of March 31, 2012, there was approximately $1.3 million of unamortized compensation expense relating to outstanding restricted shares that will be recognized in 2012 through 2015.

Warrants

On May 25, 2007, the Company entered into a Securities Purchase Agreement with certain accredited investors pursuant to which the Company issued warrants to purchase 1,174,938 shares of common stock. The warrants expire on May 25, 2012 and are exercisable at a price of $3.83 per share, subject to certain adjustments. No warrants were exercised during the three months ended March 31, 2012 and 2011. As of March 31, 2012, there were 878,000 warrants outstanding.

Oil and Gas Properties

The Company follows the full cost method of accounting for oil and gas properties. Under this method, all direct costs and certain indirect costs associated with acquisition of properties and successful as well as unsuccessful exploration and development activities are capitalized. Depreciation, depletion, and amortization of capitalized oil and gas properties and estimated future development costs, excluding unproved properties, are based on the unit-of-production method based on Proved reserves. Net capitalized costs of oil and gas properties, less related deferred taxes, are limited by country, to the lower of 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 in unusual circumstances. We apply the full cost ceiling test on a quarterly basis on the date of the latest balance sheet presented. At March 31, 2012, 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, 2012 and the year ended December 31, 2011:

	March 31, 2012	December 31, 2011
Beginning asset retirement obligation	$8,412	$7,734
Settled	(4)	(72)
Revisions	4	(9)
New wells placed on production and other	153	318
Deletions related to property disposals and plugging costs	—	(11)
Accretion expense	116	452
Ending asset retirement obligation	$8,681	$8,412

Working Capital (Deficit)

At March 31, 2012, our current liabilities of approximately $47.5 million exceeded our current assets of $19.0 million resulting in a working capital deficit of $28.5 million. This compares to a working capital deficit of $14.8 million at December 31, 2011. Current liabilities at March 31, 2012 primarily consisted of the current portion of derivative liabilities of $11.6 million, trade payables of $27.5 million and revenues due third parties of $7.2 million.

Note 2. Joint Venture

On August 18, 2010, Abraxas Petroleum and its wholly-owned subsidiary, Abraxas Operating, LLC, contributed 8,333 net acres in the Eagle Ford Shale play to Blue Eagle Energy, LLC (“Blue Eagle”) and received a $25.0 million equity interest in Blue Eagle pursuant to the terms of the Subscription and Contribution Agreement among Abraxas Petroleum, Abraxas Operating, Blue Eagle and Rock Oil Company, LLC (“Rock Oil”) formerly known as Blue Stone Oil & Gas, LLC. Simultaneously, Rock Oil contributed $25.0 million in cash to Blue Eagle for a $25.0 million equity interest. Rock Oil committed to contribute an additional $50.0 million to Blue Eagle and upon full funding (should it occur), Abraxas Petroleum would own a 25% equity interest and Rock Oil would own a 75% equity interest in Blue Eagle.

Blue Eagle’s subject area encompasses 12 counties across the Eagle Ford Shale play. Abraxas Petroleum operates the wells owned by Blue Eagle and Rock Oil and Abraxas jointly manage the day-to-day business affairs of Blue Eagle. Robert L.G. Watson, our President and CEO, serves as one of the three members of the Board of Managers of Blue Eagle.

As of March 31, 2012, Rock Oil has contributed $47.0 million to Blue Eagle and we own a non-controlling 34.7% interest in the joint venture. We account for the joint venture under the equity method of accounting. Under this method, Abraxas' share of net income (loss) from the joint venture is reflected as an increase (decrease) in its investment account in "Investment in joint venture" and is also recorded as equity investment income (loss) in "Equity in (gain) loss of joint venture." For the three months ended March 31, 2012 and 2011, we reported a gain of $783,000 and $749,000, respectively.

The following is condensed financial data from Blue Eagle's March 31, 2012 and December 31, 2011 financial statements:

Balance Sheets:	As of March 31, 2012	As of December 31, 2011
Assets:		
Current assets	$7,641	$11,910
Oil and gas properties	74,378	66,663
Other assets	34	36
Total assets	$82,053	$78,609
Liabilities and Members' Capital:		
Current liabilities	$4,252	$3,070
Other liabilities	47	41
Members' capital	77,754	75,498
Total liabilities and members' capital	$82,053	$78,609

	Three Months Ended March 31,	
Statements of Operations:	2012	2011
Revenue	$3,821	$3,097
Operating expenses	2,128	1,604
Other (income) expense	(1)	(5)
Net income	$1,694	$1,498

Blue Eagle has engaged Strategic Energy Advisors, LLC to review its strategic alternatives, including the potential sale of Blue Eagle or its assets, for which the data room opened in April 2012.

Note 3. 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, 2012, there were no current or deferred income tax expense or benefit due to losses and/or loss carryforwards and valuation allowances which have been recorded against such benefits.

The Company accounts for uncertain tax positions under provisions ASC 740-10. This ASC did not have any effect on the Company's financial position or results of operations for the three months ended March 31, 2012 and 2011. The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. As of March 31, 2012, the Company did not have any accrued interest or penalties related to uncertain tax positions. The tax years 2001 through 2011 remain open to examination by the tax jurisdictions to which the Company is subject. The Company and Abraxas Energy Partners, L.P., which was merged into a wholly-owned subsidiary of Abraxas, are currently undergoing an Internal Revenue Service audit of their 2009 Federal income tax returns.

At December 31, 2011, we had, subject to the limitation discussed below, $150.2 million of net operating loss carryforwards for U.S. tax purposes and $7.7 million of net operating loss carryforwards for Canadian tax purposes.

The U.S. loss carryforward will expire in varying amounts through 2031 and the Canadian loss carryforward will expire in 2031, if not utilized.

Note 4. Long-Term Debt

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

	March 31, 2012	December 31, 2011
Credit facility	$115,000	$115,000
Rig loan agreement	7,000	6,500
Real estate lien note	4,895	4,939
	126,895	126,439
Less current maturities	(184)	(181)
	$126,711	$126,258

Credit Facility

On June 30, 2011, we entered into a second amended and restated 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, 2012, $115.0 million was outstanding under the credit facility.

The credit facility has a maximum commitment of $300.0 million and availability is subject to a borrowing base. The borrowing base is currently $125.0 million and 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 of $125.0 million was determined based upon our reserve report dated December 31, 2011. 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, 2012, the interest rate on the credit facility was 3.53% 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. Neither the properties owned by Blue Eagle nor our investment in Blue Eagle are used to secure our obligations under the credit facility.

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 as of the last day of each quarter 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 any accounts receivable from Blue Eagle 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, and any accounts payable to Blue Eagle. 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 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; provided that net income shall be adjusted to negate the effect of non-cash gain or loss attributable to Blue Eagle. 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, and obligations with respect to surety bonds and hedge arrangements.

As of March 31, 2012, the interest coverage ratio was 7.05 to 1.00 and the total debt to EBITDAX ratio was 2.72 to 1.00.

At March 31, 2012, we were not in compliance with the financial covenant that we maintain a current ratio, as of the last day of each quarter, of not less than 1.00 to 1.00, as defined. As of March 31, 2012, the current ratio was 0.72 to 1.00. We have received a waiver from our lenders for the quarter ended March 31, 2012 with respect to this covenant breach. We anticipate that revenue increases from newly completed wells, control of capital spending, additional grants of available borrowings from our lenders, combined with the Blue Eagle divestiture will allow us to remain in compliance through the remainder of 2012 and 2013. However, not all these actions are within our control and there can be no assurance that we will be able to effect these actions on a timely basis. If we are unable to maintain compliance and the lenders were to exercise their rights, the Company may experience liquidity problems. This would have a material adverse effect on the Company, unless the lenders agree to additional waivers, forbearance, or restructuring of the debt or unless the Company can refinance the debt.

In addition to the foregoing and other customary covenants, 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 is $7.0 million and bears interest at 4.26%, which equates to the four-year interest swap rate plus 3.50% on the date of closing. Interest only is due for the first 18-months of the note and thereafter, the note will amortize 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, 2012, $7.0 million was outstanding under the rig loan agreement.

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

Real Estate Lien Note

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 bears interest at a fixed rate of 5.25% and is payable in monthly installments of principal and interest of $36,652 based on a twenty year amortization. The note matures in May 2015 at which time the outstanding balance becomes due. The note is secured by a first lien deed of trust on the property and improvements. As of March 31, 2012, $4.9 million was outstanding on the note.

Note 5. Income (Loss) Per Share

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

	Three Months Ended March 31,	
	2012	2011
Numerator:		
Net income (loss)	$ 817	$ (10,019)
Denominator:		
Denominator for basic income (loss) per share -		
Weighted-average shares	91,745	85,867
Effect of dilutive securities:		
Stock options and warrants	1,860	—
Dilutive potential common shares		
Denominator for diluted income (loss) per share -		
Weighted-average shares and assumed conversions	93,605	85,867
Net income (loss) per common share – basic	$ 0.01	$ (0.12)
Net income (loss) per common share – diluted	$ 0.01	$ (0.12)

For the three months ended March 31, 2011, none of the shares issuable in connection with stock options or warrants are included in diluted shares. Inclusion of these shares would be antidilutive due to loss incurred in the period. Had there not been a loss in the period, dilutive shares would have been 3,286,378 shares.

Note 6. 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.

On March 12, 2012, we monetized our gas hedges for net proceeds of approximately $12.4 million.

The following table sets forth our derivative contracts at March 31, 2012:

	Fixed Price Swap			
	Oil		Gas	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (MMBtu)	Swap Price (per MMBtu)
2012 (April - June)	946	$70.89	8,301	$6.77
2012 (July – December)	1,176	$78.23	—	—
2013	994	$88.03	—	—
2014 (January – August)	840	$100.71	—	—

At March 31, 2012, the aggregate fair value of our commodity derivative contracts was a liability of approximately $9.9 million.

In order to mitigate our interest rate exposure, we entered into an interest rate swap, effective August 12, 2008, to fix our floating LIBOR based debt. The two-year interest rate swap arrangement for $100 million at a fixed rate of 3.367% originally was set to expire on August 12, 2010. The interest rate swap was amended in February 2009 lowering our fixed rate to 2.95% and further amended in November 2009 lowering our fixed rate to 2.55% and extending the term through August 12, 2012.

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

Fair Value of Derivative Instruments as of March 31, 2012

	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	$ 5,091	Derivatives – current	$ 10,516
Interest rate derivatives	Derivatives – current	—	Derivatives – current	1,106
Commodity price derivatives	Derivatives - noncurrent	232	Derivatives - noncurrent	4,696
		$ 5,323		$ 16,318

Fair Value of Derivative Instruments as of December 31, 2011

	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	$11,416	Derivatives – current	$10,094
Interest rate derivatives	Derivatives – current	—	Derivatives – current	1,546
Commodity price derivatives	Derivatives - noncurrent	6,412	Derivatives - noncurrent	4,307
		$17,828		$15,947

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

Note 7. 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 carrying value of the balances outstanding under the credit facility, the rig loan agreement and the real estate lien note approximates fair value. The carrying values of cash, accounts receivable, other current receivables, accounts payable, other payables and accrued expenses included in the accompanying balance sheets approximated fair value at March 31, 2012 and December 31, 2011 due to their short term maturities. Therefore, such financial assets and liabilities are not presented in the following table; however, if these items were presented in the following table, they would be characterized as Level 3. The following tables set forth information about the Company's assets and liabilities measured at fair value, as of March 31, 2012 and December 31, 2011, and indicates the fair value hierarchy of the valuation methodology techniques utilized by the Company to determine such fair value.

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of March 31, 2012
Assets				
Investment in common stock	$101	$—	$ —	$101
NYMEX Fixed Price Derivative contracts	—	5,323	—	5,323
Total Assets	$101	$5,323	$ —	$5,424
Liabilities				
NYMEX Fixed Price Derivative contracts	$—	$15,212	$ —	$15,212
Interest Rate Swaps	—	—	1,106	1,106
Total Liabilities	$—	$15,212	$ 1,106	$16,318

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2011
Assets:				
Investment in common stock	$104	$—	$ —	$104
NYMEX Fixed Price Derivative contracts	—	17,828	—	17,828
Total Assets	$104	$17,828	$ —	$17,932
Liabilities:				
NYMEX Fixed Price Derivative contracts	$—	$14,401	$ —	$14,401

Interest Rate Swaps	—	—	1,546	1,546
Total Liabilities	$—	$14,401	$ 1,546	$15,947

The Company has an investment in Insignia Energy Ltd, the surviving entity in the merger with a former subsidiary, consisting of shares of common stock. The stock is actively traded on the Toronto Stock Exchange. This investment is valued at its quoted price as of March 31, 2012 and December 31, 2011 in U.S. dollars. Accordingly, this investment is characterized as Level 1.

The Company's derivative contracts consist of NYMEX-based fixed price commodity swaps and interest rate swaps. The NYMEX-based fixed price derivative contracts are indexed to NYMEX futures contracts, which are actively traded for the underlying commodity and 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 mitigate our interest rate exposure, we entered into an interest rate swap, effective August 12, 2008, to fix our floating LIBOR based debt. The interest rate swap arrangement for $100 million at a fixed rate of 3.367% originally was set to expire on August 12, 2010. The swap was amended in February 2009 lowering our fixed rate to 2.95% and further amended in November 2009 lowering our fixed rate to 2.55% and extending the term through August 12, 2012. As there are no observable market parameters for this type of swap, these derivative contracts are classified as Level 3.

Additional information for the Company's recurring fair value measurements using significant unobservable inputs (Level 3) for the three months ended March 31, 2012 are as follows:

	Derivative Assets (Liabilities) - net
Balance December 31, 2011	$ (1,546)
Total realized and unrealized losses included in change in net liability	(135)
Settlements during the period	575
Balance March 31, 2012	$ (1,106)

The Company relies on the counter-parties valuation of this derivative instrument and does not develop quantitative information about the significant unobservable inputs used in the fair value measurement categorized within Level 3 of the fair value hierarchy. A significant change in the LIBOR strip could impact the fair value of this derivative instrument.

Note 8. Business Segments

The following tables provide the Company's geographic operating segment data for the three months ended March 31, 2012 and 2011:

	Three Months Ended March 31, 2012			
	U.S	Canada	Corporate	Total
Revenues:				
Oil and gas production	$15,875	$504	$—	$16,379
Other	—	—	14	14
	15,875	504	14	16,393
Expenses (income):				
Lease operating	5,709	225	—	5,934
Production taxes	1,496	—	—	1,496
Depreciation, depletion and amortization	4,558	218	62	4,838
General and administrative	326	121	1,454	1,901
Net interest	112	4	1,078	1,194
Amortization of deferred financing fees	—	—	30	30
Equity in gain of joint venture	—	—	(783)	(783)
Loss on derivative contracts	—	—	924	924
Other	—	—	42	42
Net income (loss)	$3,674	$(64)	$(2,793)	$817

	Three Months Ended March 31, 2011			
	U.S	Canada	Corporate	Total
Revenues:				
Oil and gas production	$13,658	$189	$—	$13,847
Other	—	—	1	1
	13,658	189	1	13,848
Expenses (income):				
Lease operating	3,880	135	—	4,015
Production taxes	1,254	—	—	1,254
Depreciation, depletion and amortization	3,273	95	62	3,430
General and administrative	516	219	1,911	2,646
Net interest	—	—	1,603	1,603
Amortization of deferred financing fees	—	—	500	500
Equity in gain of joint venture	—	—	(749)	(749)
Loss on derivative contracts	—	—	11,093	11,093
Other	—	—	75	75
Net income (loss)	$4,735	$(260)	$(14,494)	$(10,019)

The following table provides the Company's geographic asset data as of March 31, 2012 and December 31, 2011:

Segment Assets:	March 31, 2012	December 31, 2011
United States	$185,067	$167,739
Canada	24,490	19,379

Corporate	42,295	54,032
	$251,852	$241,150

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Note 9. 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, 2012, 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. The Company and Abraxas Energy Partners, L.P., which was merged into a wholly-owned subsidiary of Abraxas, are currently undergoing an Internal Revenue Service audit of their 2009 Federal income tax returns.

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, 2011 filed with the SEC on March 15, 2012.

The results of operations set forth below do not include our interest in the operations of Blue Eagle.

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, 2011.

General

We are an independent energy company engaged in the 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 three of the last five years, we cannot assure you that we can achieve positive net income in the future. 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, 2012, the New York Mercantile (NYMEX) price for West Texas Intermediate crude oil (WTI) averaged $103.03 per barrel as compared to $94.48 per barrel during the three months ended March 31, 2011. NYMEX Henry Hub spot prices for gas averaged $2.44 per MMBtu for the three months ended March 31, 2012 compared to $4.18 for the same period of 2011. Prices closed on March 31, 2012 at $103.02 per Bbl of oil and $1.96 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, 2012 and 2011:

	Oil - WTI		Gas – Henry Hub	
	2012	2011	2012	2011
Average realized price (1)	$91.42	$85.13	$2.16	$3.62
Average NYMEX price	$103.03	$94.48	$2.44	$4.18
Differential	$(11.61)	$(9.35)	$(0.28)	$(0.56)

(1) excluding 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.

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. In the three months ended March 31, 2012, we recognized a realized gain of $529,000 and an unrealized loss of $1.3 million on our commodity swaps. For the three months ended March 31, 2011, we incurred a realized gain of $457,000 and an unrealized loss of $11.4 million. We have not designated any of these derivative contracts as a hedge as prescribed by applicable accounting rules.

On March 12, 2012, we monetized our gas hedges for net proceeds of approximately $12.4 million.

The following table sets forth our derivative contracts at March 31, 2012:

	Fixed Price Swap			
	Oil		Gas	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (MMBtu)	Swap Price (per MMBtu)

2012 (April - June)	946	$70.89	8,301	$6.77
2012 (July – December)	1,176	$78.23	—	—
2013	994	$88.03	—	—
2014 (January – August)	840	$100.71	—	—

At March 31, 2012, the aggregate fair value of our oil and gas derivative contracts was a liability of approximately $9.9 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, 2011 (which did not include any Blue Eagle reserves), the average annual estimated decline rate for our net proved developed producing reserves is 14% during the first five years, 8% in the next five years, and approximately 7% 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 $26.1 million during the three months ended March 31, 2012. We have a capital expenditure budget for 2012 of approximately $70.0 million. Approximately 75% of the 2012 budget will be spent on unconventional horizontal oil wells in the Bakken/Three Forks and Niobrara/Turner plays in the Rocky Mountain region of the United States and the other 25% will target conventional oil plays in the Permian Basin and in the province of Alberta, Canada. The 2012 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.

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, 2012, we had $10.0 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 large inventory of drilling projects position us for future growth. At December 31, 2011, 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 leasehold, the successful development of which we believe could significantly increase our production and Proved reserves.

Our future 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 properties and our Proved reserves will decline as our reserves are produced unless we acquire or develop additional properties containing Proved 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 will also decline. In addition, approximately 43% of our estimated Proved reserves at December 31, 2011 were undeveloped. By their nature, estimates of Proved 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

Rocky Mountain – North Dakota / Montana

- In McKenzie County, the Company owned drilling rig is currently drilling the Ravin 26-35 2H and Ravin 26-35 3H concurrently from a multi-pad well site. The surface casing has been drilled on the 3H, after which the rig walked to the 2H. The rig is currently drilling the intermediate casing on the 2H, after which it will walk back to the 3H to complete the drilling. Abraxas owns an approximate 49% working interest in each of these wells.
- In the Bakken / Three Forks play in the Williston Basin, during the first quarter of 2012, 10 gross (0.85 net) non-operated wells came on-line and 5 gross (0.06 net) wells are currently drilling or awaiting completion. Additionally, we have recently elected to participate in 1 gross (0.01 net) well that has yet to spud.

Rocky Mountain – Wyoming

- In Campbell County, Wyoming, the Hedgehog State 16-2H, a horizontal well targeting the Turner formation, was placed on-line in April 2012. The well continues to be very strong; however, we are choking the well back to manage the reservoir in a prudent manner. Abraxas owns a 100% working interest in this well.

South Texas – Eagle Ford

- At March 31, 2012, Abraxas owned a 34.7% equity interest in Blue Eagle, a joint venture between Abraxas and Rock Oil Company, LLC, exclusively targeting the Eagle Ford shale.
- In McMullen County, Texas, the Cobra 1H, was placed on-line in March 2012. The well continues to produce at very strong rates. The Cobra 1H was the fourth well drilled under the Blue Eagle JV, with Abraxas being the operator. Blue Eagle owns a 100% working interest in this well.
- Blue Eagle has retained Strategic Energy Advisors, LLC to assist in the sale of Blue Eagle's Eagle Ford holdings and the process is currently underway.

Canada – Pekisko

- In Alberta, Canada, the pipeline hook-up for three wells was completed and production commenced in early April 2012. Two additional wells still await stimulation as the completions have been delayed until after Spring break-up. Canadian Abraxas owns a 100% working interest in each of these wells which have targeted the Pekisko formation.
- In Alberta, Canada, Canadian Abraxas has accumulated approximately 20,000 net acres in an emerging oil shale play which has very similar characteristics to the oil window in the Eagle Ford shale play.

Results of Operations

Results of Operations do not include our interest in the operations of Blue Eagle.

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

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
Operating revenue: (1)		
Oil sales	$13,393	$9,885
Gas sales	2,061	3,772
NGL sales	925	190
Other	14	1
	$16,393	$13,848
Operating income	$2,224	$2,503
Oil sales (MBbl)	147	116
Gas sales (MMcf)	954	1,041
NGL sales (MBbl)	21	4
BOE sales	327	294
Average oil sales price ($/Bbl) (1)	$91.42	$85.13
Average gas sales price ($/Mcf) (1)	$2.16	$3.62
Average NGL sales price ($/Bbl)	$43.89	$47.64
Average BOE sales price	$50.15	$47.15

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

Comparison of Three Months Ended March 31, 2012 to Three Months Ended March 31, 2011

Operating Revenue. During the three months ended March 31, 2012, operating revenue increased to $16.4 million compared to $13.8 million during the same period of 2011. The increase was due to higher sales volumes and higher oil prices. Increased oil prices contributed $0.8 million, while increased oil and NGL volumes contributed $3.5 million to revenue. Lower realized prices for gas and NGL as well as lower gas volumes had a negative impact of $1.7 million for the three months ended March 31, 2012.

Oil sales volumes increased to 147 MBbls for the three months ended March 31, 2012 from 116 MBbls for the same period of 2011. The increase in oil sales volumes was due to new wells being brought on line, offset by natural field declines. New wells brought onto production since the first quarter of 2011 contributed 33 MBbls to production for the three months ended March 31, 2012. Gas sales volumes decreased to 954 MMcf for the three months ended March 31, 2012 from 1,041 MMcf for the same period of 2011. The decrease in gas sales volumes was due to natural field declines. NGL sales volumes increased to 21 MBbl for the three months ended March 31, 2012 from 4 MBbl for the same period of 2011. 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, 2012 increased to $5.9 million from $4.0 million for the same period in 2011. The increase in LOE was primarily due to significant workovers performed during the quarter as well as a general increase in the cost of services. LOE per Boe for the three months ended March 31, 2012 was $18.17 compared to $13.68 for the same period of 2011. The increase per Boe was primarily due to higher cost somewhat offset by an overall increase in production for the three months ended March 31, 2012 as compared to the same period of 2011.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the three months ended March 31, 2012 increased to $1.5 million from $1.3 million for the same period of 2011. Increased production taxes resulting from higher oil prices and sales volumes were offset by lower gas prices and sales volumes for the first quarter of 2012 as compared to the same period of 2011.

General and Administrative ("G&A") Expenses. G&A expenses, excluding stock-based compensation, for the three months ended March 31, 2012 decreased to $1.4 million from $2.3 million for the same period of 2011. The decrease in G&A was primarily related to bonuses paid in 2011, as there were no bonuses paid in the three months ended March 31, 2012. G&A per Boe was $4.36 for the three months ended March 31, 2012 compared to $7.77 for the same period of 2011. The decrease per Boe was primarily due to decreased G&A expense for the three months ended March 31, 2012 compared to the same period in 2011.

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, 2012 and 2011, stock-based compensation was approximately $477,000 and $363,000, respectively. The increase in 2012 as compared to 2011 was due to stock option grants in the third quarter of 2011 and the first quarter of 2012.

Depreciation, Depletion and Amortization ("DD&A") Expenses. DD&A expense for the three months ended March 31, 2012 increased to $4.8 million from $3.4 million for same period of 2011. The increase in DD&A was primarily the result of increased future development cost in our 2011 year-end reserve report. DD&A per Boe for the three months ended March 31, 2012 was $14.82 compared to $11.68 in 2011.

Interest Expense. Interest expense for the three months ended March 31, 2012 decreased to $1.2 million from $1.6 million for the same period of 2011. The decrease in interest expense was primarily due to lower interest rates as compared to the same period of 2011.

Loss (gain) on derivative contracts. We account for derivative contract gains and losses based on realized and unrealized amounts. The realized derivative gains or losses are determined by actual derivative settlements during the period. Unrealized gains and losses are based on the periodic mark to market valuation of derivative contracts in place. 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. Our derivative contracts consist of commodity swaps and interest rate swaps. The estimated value of our derivative contracts was a liability of approximately $11.0 million as of March 31, 2012, consisting of our commodity derivative contracts at a liability of $9.9 million and our interest rate swap at a liability of $1.1 million. 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, 2012, we realized a loss on our derivative contracts of $48,000, which included a realized gain of $529,000 on our commodity swaps and a realized loss of $577,000 on our interest rate swap. For the three months ended March 31, 2012, we incurred an unrealized loss of $876,000 on our derivative contracts, which included an unrealized loss of $1.3 million on our commodity swaps and an unrealized gain of $442,000 on our interest rate swap. For the three months ended March 31, 2011, we realized a loss on our derivative contracts of $115,000, which included a realized gain of $457,000 on our commodity swaps and a realized loss of $572,000 on our interest rate swap. For the three months ended March 31, 2011, we incurred an unrealized loss of $11.0 million on our derivative contracts, which included an unrealized loss of $11.4 million on our commodity swaps and an unrealized gain of $423,000 on our interest rate swap.

Equity in (gain) loss of joint venture. We account for Blue Eagle under the equity method of accounting. Under this method, Abraxas' share of net gain (loss) from the joint venture is reflected as an increase (decrease) in its investment account in "Investment in joint venture" and is also recorded as equity investment gain (loss) in "Equity in loss (gain) of joint venture." For the three months ended March 31, 2012, our net equity interest in the joint venture's income was $783,000. As of March 31, 2012, we owned a 34.7% equity interest in Blue Eagle.

The following table represents our equity interest in Blue Eagle's production:

	Three Months Ended March 31, 2012
Oil production (MBbl)	10
Gas production (MMcf)	43
NGL production (MBbl)	4
Average oil sales price ($/Bbl)	$107.43
Average gas sales price ($/Mcf)	$2.74
Average NGL sales price ($/Bbl)	$42.85

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 of existing properties, including drilling and completion costs of wells;
- acquisition of additional properties;
- acquisition of additional interest in existing 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. During the three months ended March 31, 2012, we completed the refurbishment of our drilling rig and have deployed it to North Dakota. We do not anticipate further significant capital expenditures related to the rig.

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.

Working Capital (Deficit). At March 31, 2012, our current liabilities of approximately $47.5 million exceeded our current assets of $19.0 million resulting in a working capital deficit of $28.5 million. This compares to a working capital deficit of $14.8 million at December 31, 2011. Current liabilities at March 31, 2012 primarily consisted of the current portion of derivative liabilities of $11.6 million, trade payables of $27.5 million and revenues due third parties of $7.2 million.

Capital expenditures. Capital expenditures during the three months ended March 31, 2012 were $26.1 million compared to $9.8 million during the same period of 2011.

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

	Three Months Ended March 31,	
	2012	2011
Expenditure category:		
Development	$22,773	$9,667
Facilities and other	3,353	98
Total	$26,126	$9,765

During the three months ended March 31, 2012, capital expenditures were primarily for development of our existing oil and gas properties and the completion of the refurbishment of our drilling rig. During the three months ended March 31, 2011, capital expenditures were primarily for development of our existing oil and gas properties. We anticipate making capital expenditures in 2012 of $70.0 million. The 2012 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. With the increased number of drilling rigs running, particularly in the Williston Basin and in the Eagle Ford Shale play, together with the increased number of stages on a given frac job, frac crews and equipment have been in short supply. As a result, we have experienced and may in the future experience delays in procuring services for the multi-stage frac jobs that we have planned for our operated wells, which would delay the completion of successfully drilled wells. 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,	
	2012	2011
Net cash provided by (used in) operating activities	$25,788	$(4,928)
Net cash used in investing activities	(26,126)	(1,308)
Net cash provided by financing activities	338	7,096
Total	$—	$860

Operating activities during the three months ended March 31, 2012 provided $25.8 million of cash compared to using $4.9 million in the same period of 2011. Net income plus non-cash expense items during the three months ended March 31, 2012 and 2011 and net changes in operating assets and liabilities accounted for most of these funds, in addition the monetization of our gas hedges on March 12, 2012 which provided $12.4 million. Investing activities used $26.1 million during the three months ended March 31, 2012 compared to using $1.3 million for the same period of 2011. Funds used during the three months ended March 31, 2012 were expenditures for the development of our existing properties and the completion of the refurbishment of our drilling rig. Funds used during the three months ended March 31, 2011 were expenditures for the development of our existing properties. Financing activities provided $338,000 for the three months ended March 31, 2012 compared to providing $7.1 million for the same period in 2011. Funds provided during the three months ended March 31, 2012 were primarily proceeds from borrowings under the rig loan, and funds provided during the three months ended March 31, 2011 were primarily from the proceeds of our equity offering in February 2011 of $62.1 million, offset by payments on our long term debt of $57.0 million.

Future Capital Resources. Our principal sources of capital going forward 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 financing on terms acceptable to us, if at all.

Cash from operating activities is dependent upon commodity prices and production volumes. Oil and gas prices are volatile. Oil prices have increased significantly from their low in 2009 but gas prices have remained weak. 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 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. Additionally, due to the increased number of drilling rigs running, particularly in the Williston Basin and in the Eagle Ford Shale play, together with the increased number of stages on a given frac job, frac crews and equipment have been in short supply. As a result, there may be a delay in procuring services for the multi-stage frac jobs that we have planned for our operated wells, which would delay the completion of successfully drilled wells. If our proved reserves decline in the future, our production will also decline and, consequently, our cash flow from operations and the amount that we are able to borrow under our credit facility will also decline. The risk of not finding commercially productive reservoirs will be compounded by the fact that 43% of our total estimated Proved reserves at December 31, 2011 were classified as Proved undeveloped reserves.

We have in the past and may in the future sell producing properties. Most recently, in the fourth quarter of 2009 and throughout 2010, we sold certain non-operated, non-core assets for combined net proceeds of approximately $32.2 million. The net proceeds were used to repay outstanding indebtedness under our credit facility, for capital expenditures and general corporate purposes. Blue Eagle has engaged Strategic Energy Advisors, LLC to review its strategic alternatives, including the potential sale of Blue Eagle or its assets, for which the data room opened in April 2012.

We have also sold debt and equity securities in the past when the opportunity has presented itself. On February 1, 2011, we closed a public offering of 23.6 million shares of common stock (of which 8.5 million shares were sold by certain selling stockholders) at a public offering price of $4.40 per share for total net proceeds to us of approximately $62.2 million. We used the net proceeds from the offering to repay outstanding indebtedness under our credit facility, to increase our 2011 capital expenditure budget and for general corporate purposes. We did not receive any proceeds from the sale of shares by the selling stockholders.

On March 12, 2012, we monetized our gas hedges for net proceeds of approximately $12.4 million.

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, 2012:

		Payments due in twelve month periods ending:			
	Total	March 31, 2013	March 31, 2014-2015	March 31, 2016-2017	Thereafter
Long-term debt (1)	$126,895	$184	$3,271	$123,440	$—
Interest on long-term debt (2)	14,950	4,614	9,110	1,226	—
Lease obligations (3)	95	57	38	—	—
Total	$141,940	$4,855	$12,419	$124,666	$—

(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 Calgary, Alberta, which expires on January 31, 2014 and office space in Dickinson, North Dakota, which expires on September 30, 2012.

We maintain a reserve for cost associated with the retirement of tangible long-lived assets. At March 31, 2012, our reserve for these obligations totaled $8.7 million for which no contractual commitment exists. For additional information relating to this obligation, see Note 1 of the Notes to Consolidated Financial Statements.

Off-Balance Sheet Arrangements. At March 31, 2012, 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, 2012, 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, 2012	December 31, 2011
Credit facility	$115,000	$115,000
Rig loan agreement	7,000	6,500
Real estate lien note	4,895	4,939
	126,895	126,439
Less current maturities	(184)	(181)
	$126,711	$126,258

Credit Facility

On June 30, 2011, we entered into a second amended and restated 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, 2012, $115.0 million was outstanding under the credit facility.

The credit facility has a maximum commitment of $300.0 million and availability is subject to a borrowing base. The borrowing base is currently $125.0 million and 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 of $125.0 million was determined based upon our reserve report dated December 31, 2011. 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, 2012, the interest rate on the credit facility was 3.53% 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. Neither the properties owned by Blue Eagle nor our investment in Blue Eagle are used to secure our obligations under the credit facility.

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 as of the last day of each quarter 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 any accounts receivable from Blue Eagle 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, and any accounts payable to Blue Eagle. 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 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; provided that net income shall be adjusted to negate the effect of non-cash gain or loss attributable to Blue Eagle. 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, and obligations with respect to surety bonds and hedge arrangements.

As of March 31, 2012, the interest coverage ratio was 7.05 to 1.00 and the total debt to EBITDAX ratio was 2.72 to 1.00.

At March 31, 2012, we were not in compliance with the financial covenant that we maintain a current ratio, as of the last day of each quarter, of not less than 1.00 to 1.00, as defined. As of March 31, 2012, the current ratio was 0.72 to 1.00. We have received a waiver from our lenders for the quarter ended March 31, 2012 with respect to this covenant breach. We anticipate that revenue increases from newly completed wells, control of capital spending, additional grants of available borrowings from our lenders, combined with the Blue Eagle divestiture will allow us to remain in compliance through the remainder of 2012 and 2013. However, not all these actions are within our control and there can be no assurance that we will be able to effect these actions on a timely basis. If we are unable to maintain compliance and the lenders were to exercise their rights, the Company may experience liquidity problems. This would have a material adverse effect on the Company, unless the lenders agree to additional waivers, forbearance, or restructuring of the debt or unless the Company can refinance the debt.

In addition to the foregoing and other customary covenants, 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 is $7.0 million and bears interest at 4.26%, which equated to the four-year interest swap rate plus 3.50% on the date of closing. Interest only is due for the first 18-months of the note and thereafter the note will amortize 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, 2012, $7.0 million was outstanding under the rig loan agreement.

The Company has guaranteed Raven Drilling's obligations under the rig loan agreement and associated notes. 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 bears interest at a fixed rate of 5.25% and is payable in monthly installments of principal and interest of $36,652 based on a twenty year amortization. The note matures in May 2015 at which time the outstanding balance becomes due. The note is secured by a first lien deed of trust on the property and improvements. As of March 31, 2012, $4.9 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.

On March 12, 2012, we monetized our gas hedges for net proceeds of approximately $12.4 million.

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The following table sets forth our derivative contract position as of March 31, 2012:

	Fixed Price Swap			
	Oil		Gas	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (MMBbtu)	Swap Price (per MMBtu)
2012 (April - June)	946	$70.89	8,301	$6.77
2012 (July – December)	1,176	$78.23	—	—
2013	994	$88.03	—	—
2014 (January – August)	840	$100.71	—	—

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. For the three months ended March 31, 2012, we incurred a realized gain of approximately $529,000 and an unrealized loss of approximately $1.3 million on our commodity derivative contracts as compared to a realized gain of approximately $457,000 and an unrealized loss of approximately $11.4 million on our commodity derivative contracts during the same period of 2011. 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—Hedging Sensitivity" for further information.

Net Operating Loss Carryforwards.

At December 31, 2011, we had, subject to the limitation discussed below, $150.2 million of net operating loss carryforwards for U.S. tax purposes and $7.7 million of net operating loss carryforwards for Canadian tax purposes. The U.S. loss carryforward will expire in varying amounts through 2031 and the Canadian loss carryforward will expire in 2031, if not utilized.

Uncertainties exist as to the future utilization of the net operating loss carryforwards under the criteria set forth under ASC 740-10. Therefore, we have established a valuation allowance of $83.5 million for deferred tax assets at December 31, 2011.

We account for uncertain tax positions under 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 year ended December 31, 2011 or for the three months ended March 31, 2012. The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. As of March 31, 2012, the Company did not have any accrued interest or penalties related to uncertain tax positions. The tax years from 2001 through 2011 remain open to examination by the tax jurisdictions to which the Company is subject. The Company and Abraxas Energy Partners, L.P., which was merged into a wholly-owned subsidiary of Abraxas, are currently undergoing an Internal Revenue Service audit of their 2009 Federal income tax returns.

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, 2012, a 10% decline in oil and gas prices would have reduced our operating revenue, cash flow and net income by approximately $1.6 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.

The following table sets forth our derivative contract position as of March 31, 2012:

	Fixed Price Swap			
	Oil		Gas	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (MMBtu)	Swap Price (per MMBtu)
2012 (April - June)	946	$70.89	8,301	$6.77
2012 (July – December)	1,176	$78.23	—	—
2013	994	$88.03	—	—
2014 (January – August)	840	$100.71	—	—

In order to mitigate our interest rate exposure, we entered into an interest rate swap, effective August 12, 2008, to fix our floating LIBOR based debt. The two-year interest rate swap arrangement for $100 million at a fixed rate of 3.367% originally was set to expire on August 12, 2010. The interest rate swap was amended in February 2009 lowering our fixed rate to 2.95% and further amended in November 2009 lowering our fixed rate to 2.55% and extending the term through August 12, 2012.

At March 31, 2012, the aggregate fair market value of our commodity derivative contracts was a liability of approximately $9.9 million and the aggregate fair market value of our interest rate swap was a liability of approximately $1.1 million.

For the three months ended March 31, 2012, we recognized a realized gain of $529,000 and an unrealized loss of $1.3 million on our commodity derivative contracts and we recognized a realized loss of $577,000 and an unrealized gain of $442,000 on our interest rate swap.

Interest rate risk

We are subject to interest rate risk associated with borrowings under our credit facility. As of March 31, 2012, we had $115.0 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) 1.5%—2.75%, depending on the utilization of the borrowing base, or, if we elect, at the greater of (1) 2.0% and (2) LIBOR plus, in each case, 2.5%—3.75%, depending on the utilization of the borrowing base. At March 31, 2012, the interest rate on the credit facility was 3.53% based on 1-month LIBOR borrowings and level of utilization. For every percentage point that the LIBOR rate rises, our interest expense would increase by approximately $1.2 million on an annual basis.

In order to mitigate our interest rate exposure, we entered into an interest rate swap, effective August 12, 2008, to fix our floating LIBOR based debt. The two-year interest rate swap arrangement for $100 million at a fixed rate of 3.367% originally was set to expire on August 12, 2010. The interest rate swap was amended in February 2009 lowering our fixed rate to 2.95% and further amended in November 2009 lowering our fixed rate to 2.55% and extending the term through August 12, 2012.

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, 2012 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, 2012, 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. The Company and Abraxas Energy Partners, L.P., which was merged into a wholly-owned subsidiary of Abraxas, are currently undergoing an Internal Revenue Service audit of their 2009 Federal income tax returns.

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, 2011, 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.

N/A

Item 5. Other Information.

None

Item 6. Exhibits.

(a)	Exhibits
Exhibit 31.1	Certification - Robert L.G. Watson, CEO
Exhibit 31.2	Certification – Barbara M. Stuckey, 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 – Barbara M. Stuckey, 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 10, 2012	By: /s/Robert L.G. Watson ROBERT L.G. WATSON, President and Principal Executive Officer
Date: May 10, 2012	By: /s/Barbara M. Stuckey BARBARA M. STUCKEY, Vice President and Principal Financial Officer
Date: May 10, 2012	By: /s/G. William Krog, Jr. G. WILLIAM KROG, JR., Principal Accounting Officer