ABRAXAS PETROLEUM CORP
Form 10-Q
August 09, 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 JUNE 30, 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 August 6, 2012 was 92,335,057 shares.

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 wereshut-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)

	June 30, 2012 (Unaudited)	December 31, 2011
Assets		
Current assets:		
Cash and cash equivalents	$308	$—
Accounts receivable, net:		
Joint owners	1,801	3,354
Oil and gas production	8,850	8,897
Other	754	655
	11,405	12,906
Derivative asset – current	2,535	11,416
Other current assets	455	391
Total current assets	14,703	24,713
Property and equipment:		
Oil and gas properties, full cost method of accounting:		
Proved	521,919	490,908
Unproved properties excluded from depletion	2,185	1,100
Other property and equipmet	37,290	33,783
Total	561,394	525,791
Less accumulated depreciation, depletion, and amortization	(358,232)	(346,239)
Total property and equipment – net	203,162	179,552
Investment in joint venture	28,249	26,215
Deferred financing fees, net	3,797	3,490
Derivative asset – long-term	2,640	6,412
Other assets	744	768
Total assets	$253,295	$241,150

See accompanying notes to condensed consolidated financial statements (unaudited)

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

	June 30, 2012 (Unaudited)	December 31, 2011
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$ 18,491	$ 21,373
Oil and gas production payable	7,208	5,835
Accrued interest	151	209
Other accrued expenses	1,319	284
Derivative liability – current	4,058	11,640
Current maturities of long-term debt	186	181
Total current liabilities	31,413	39,522
Long-term debt, excluding current maturities	136,664	126,258
Derivative liability – long-term	1,128	4,307
Future site restoration	8,716	8,412
Total liabilities	177,921	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; 92,335,057 and 92,261,057 issued and outstanding	923	923
Additional paid-in capital	249,738	248,480
Accumulated deficit	(174,748)	(186,465)
Accumulated other comprehensive loss	(539)	(287)
Total stockholders' equity	75,374	62,651
Total liabilities and stockholders' equity	$ 253,295	$ 241,150

See accompanying notes to condensed consolidated financial statements (unaudited)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Revenue:				
Oil and gas production revenues	$15,934	$16,653	$32,313	$30,500
Other	4	3	18	4
	15,938	16,656	32,331	30,504
Operating costs and expenses:				
Lease operating expenses	5,382	5,566	11,316	9,581
Production taxes	1,489	1,426	2,985	2,680
Depreciation, depletion, and amortization	5,380	3,780	10,218	7,210
Impairment	1,306	—	1,306	—
General and administrative (including stock-based compensation of $722, $706, $1,199 and $1,069)	2,404	2,446	4,305	5,092
	15,961	13,218	30,130	24,563
Operating income (loss)	(23)	3,438	2,201	5,941
Other (income) expense:				
Interest income	(1)	(2)	(2)	(4)
Interest expense	1,270	1,336	2,465	2,941
Amortization of deferred financing fee	266	770	296	1,270
(Gain) loss on derivative contracts - realized	(914)	1,113	(866)	1,228
(Gain) loss on derivative contracts – unrealized	(10,296)	(7,959)	(9,420)	3,019
Equity in income of joint venture	(1,251)	(769)	(2,034)	(1,518)
Other	—	12	42	87
	(10,926)	(5,499)	(9,519)	7,023
Net income (loss)	$10,903	$8,937	$11,720	$(1,082)
Net income (loss) per common share – basic	$0.12	$0.10	$0.13	$(0.01)
Net income (loss) per common share – diluted	$0.12	$0.10	$0.13	$(0.01)

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 June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Consolidated net income (loss)	$10,903	$8,937	$11,720	$(1,082)
Change in unrealized value of investments	(34)	(20)	(38)	(4)
Foreign currency translation adjustment	(500)	4	(215)	124
Other comprehensive income (loss):	(534)	(16)	(253)	120
Comprehensive income (loss)	$10,369	$8,921	$11,467	$(962)

See accompanying notes to condensed consolidated financial statements (unaudited)

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

	Six Months Ended June 30, 2012	2011
Operating Activities		
Net (loss) income	$11,720	$(1,082)
Adjustments to reconcile net (loss) income to net cash provided by operating activities:		
Equity in income of joint venture	(2,034)	(1,518)
Change in derivative fair value	(10,472)	3,097
Monetization of derivative contracts	12,364	—
Depreciation, depletion, and amortization	10,218	7,210
Impairment	1,306	—
Amortization of deferred financing fees	296	1,270
Accretion of future site restoration	235	221
Stock-based compensation	1,199	1,069
Changes in operating assets and liabilities:		
Accounts receivable	1,507	1,770
Other	(79)	69
Accounts payable and accrued expenses	(517)	(5,527)
Net cash provided by operating activities	25,743	6,579
Investing Activities		
Capital expenditures, including purchases and development of properties	(35,116)	(25,622)
Proceeds from sale of oil and gas properties	—	8,457
Net cash used in investing activities	(35,116)	(17,165)
Financing Activities		
Proceeds from long-term borrowings	14,500	12,000
Payments on long-term borrowings	(4,089)	(58,075)
Deferred financing fees	(603)	(1,527)
Proceeds from issuance of common stock	—	62,224
Other	(128)	16
Net cash provided by financing activities	9,680	14,638
Effect of exchange rate changes on cash	1	—
Increase in cash	308	4,052
Cash and equivalents, at beginning of period	—	99
Cash and equivalents, at end of period	$308	$4,151
Supplemental disclosure of cash flow information:		
Interest paid	$2,289	$2,968

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 June 30, 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 Corporatio all 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 June 30,		Six Months Ended June 30,	
2012	2011	2012	2011
$ 599	$ 599	$ 944	$ 866

The following table summarizes the Company's stock option activity for the six months ended June 30, 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	408	$3.51	$2.56	1,044
Exercised	(67)	$0.89	$0.43	(29)
Outstanding, June 30, 2012	5,097	$2.70	$1.81	$9,229

The following table shows the weighted average assumptions used in the Black-Scholes calculation of the fair value of stock option grants for the six months ended June 30, 2012:

Expected dividend yield	0	%
Volatility	80.75	%
Risk free interest rate	1.36	%
Expected life	7.00	Years
Fair value of options granted (in thousands)	$1,044	
Weighted average grant date fair value per share of options granted	$2.56	

Additional information related to stock options at June 30, 2012 and December 31, 2011 is as follows:

	June 30, 2012	December 31, 2011
Options exercisable	3,076	2,512

As of June 30, 2012, there was approximately $3.2 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 six months ended June 30, 2012:

	Number of Shares	Weighted Average Grant Date Fair Value Per Share
Unvested, December 31, 2011	630	$3.03
Granted	7	3.16
Vested/Released	(111)	1.86
Forfeited	—	—
Unvested, June 30, 2012	526	$3.28

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

Three Months Ended June 30,		Six Months Ended June 30,	
2012	2011	2012	2011
$123	$ 107	$ 255	$ 203

As of June 30, 2012, there was approximately $1.2 million of unamortized compensation expense relating to outstanding restricted shares that will be recognized in 2012 through 2016.

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 expired on May 25, 2012.

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 June 30, 2012, our net capitalized costs of oil and gas properties in the United States did not exceed the cost ceiling of our estimated Proved reserves, however, the net capitalized cost of oil and gas properties in Canada exceeded the cost ceiling by $1.3 million resulting in a write down for the six months ended June 30, 2012.

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 six months ended June 30, 2012 and the year ended December 31, 2011:

	June 30, 2012	December 31, 2011
Beginning asset retirement obligation	$8,412	$7,734
Settled	(210)	(83)
Revisions	123	(9)
New wells placed on production and other	156	318
Accretion expense	235	452
Ending asset retirement obligation	$8,716	$8,412

Working Capital (Deficit)

At June 30, 2012, our current liabilities of approximately $31.4 million exceeded our current assets of $14.7 million resulting in a working capital deficit of $16.7 million. This compares to a working capital deficit of $14.8 million at December 31, 2011. Current liabilities at June 30, 2012 primarily consisted of the current portion of derivative liabilities of $4.1 million, trade payables of $18.5 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 June 30, 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 and six months ended June 30, 2012 and 2011 we reported a gain of $1.3 million, $2.0 million, $769,000 and $1.5 million, respectively, related to Blue Eagle.

The following is condensed financial data from Blue Eagle's June 30, 2012 and December 31, 2011 financial statements:

Balance Sheets:	As of June 30, 2012	As of December 31, 2011
Assets:		
Current assets	$7,089	$11,910
Oil and gas properties	75,875	66,663
Other assets	31	36
Total assets	$82,995	$78,609
Liabilities and Members' Capital:		
Current liabilities	$1,592	$3,070
Other liabilities	47	41
Members' capital	81,356	75,498
Total liabilities and members' capital	$82,995	$78,609

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Revenue:	$5,946	$3,758	$9,767	$6,855
Operating expenses	2,899	1,544	5,027	3,148
Other (income) expense	—	(4)	(1)	(9)
Net income:	$3,047	$2,218	$4,741	$3,716

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 and six months ended June 30, 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 six months ended June 30, 2012 and 2011. The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. As of June 30, 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, have undergone audits of their 2009 Federal income tax returns. The audit of the Federal income tax return of Abraxas Energy Partners, L.P. was completed with no changes. The audit of Abraxas Petroleum Corporation resulted in a notice of proposed adjustment of $686,000. The Company does not agree with the findings and intends to aggressively appeal the proposed adjustment; however, no assurances can be made that such appeals will be successful.

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 $8.7 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:

	June 30, 2012	December 31, 2011
Credit facility	$125,000	$115,000
Rig loan agreement	7,000	6,500
Real estate lien note	4,850	4,939
	136,850	126,439
Less current maturities	(186)	(181)
	$136,664	$126,258

Credit Facility

On June 29, 2012, we entered into an amendment to our 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 June 30, 2012, $125.0 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 $140.0 million. This amount will remain in effect until the earliest of (a) the sale of our interest in Blue Eagle, (b) the date on which the borrowing base is redetermined based upon our internal engineering report as of June 30, 2012, and (c) October 31, 2012. The borrowing base is determined semi-annually by the lenders based upon our reserve reports, one of which must be prepared by our independent petroleum engineers and one of which may be prepared internally. The amount of the borrowing base is calculated by the lenders based upon their valuation of our Proved reserves securing the facility utilizing these reserve reports and their own internal decisions. In addition, the lenders, in their sole discretion, are able to make one additional borrowing base redetermination during any six-month period between scheduled redeterminations and we are able to request one redetermination during any six-month period between scheduled redeterminations. The borrowing base will be automatically reduced in connection with any sales of producing properties with a market value of 5% or more of our then-current borrowing base and in connection with any hedge termination which could reduce the collateral value by 5% or more. Our borrowing base of $140.0 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 June 30, 2012, the interest rate on the credit facility was 3.50% 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 of not less than 2.50 to 1.00. We are also required as of the last day of each quarter to maintain a total debt to EBITDAX ratio as of the last day of each quarter of not more than 4.00 to 1.00 and until the earlier of the date we sell our interest in Blue Eagle or December 31, 2012, liquidity (defined as sum of our borrowing base availability, liquid investments and unrestricted cash) of $7.5 million. 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 June 30, 2012, the interest coverage ratio was 7.38 to 1.00, the total debt to EBITDAX ratio was 2.85 to 1.00 and our current ratio was 1.09 to 1.0 and we had liquidity of $15.3 million.

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.

In addition, until the earlier of the end of 2012 or the date that our interest in Blue Eagle is sold, we are required to limit our capital expenditures for drilling / completion expenditures to $10.0 million per quarter, subject to certain pull-back and carry-over provisions; however, if we maintain a borrowing base availability percentage (defined as the amount available under the credit facility divided by the amount borrowed under the credit facility) of not less than 15% at June 30, 2012 and 10% at September 30, 2012 and December 31, 2012, capital expenditures in the ordinary course of business are not subject to the limitation. At June 30, 2012, our borrowing base availability percentage was 12% and, as a result, we will be subject to this limitation during the third quarter ended September 30, 2012, excluding $7.2 million for the acquisition of producing properties for the quarter ending September 30, 2012. 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 June 30, 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 June 30, 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 June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Numerator:				
Net income (loss)	$10,903	$8,937	$11,720	$(1,082)
Denominator:				
Denominator for basic income (loss) per share -				
Weighted-average shares	91,808	91,409	91,775	88,653
Effect of dilutive securities:				
Stock options and warrants	1,455	2,097	1,673	—
Denominator for diluted income (loss) per share - adjusted weighted-average shares and assumed conversions	93,263	93,506	93,448	88,653
Net income (loss) per common share – basic	$0.12	$0.10	$0.13	$(0.01)
Net income (loss) per common share – diluted	$0.12	$0.10	$0.13	$(0.01)

For the six months ended June 30, 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 the loss incurred in the period. Had there not been a loss for the period, dilutive shares would have been 2,328 shares for the six months ended June 30, 2011.

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.

The following table sets forth our derivative contracts at June 30, 2012:

	Fixed Price Swap
	Oil
Contract Periods	Swap Price

	Daily Volume (Bbl)	(per Bbl)
2012 (July – September)	1,176	$78.23
2012 (October – December)	1,509	$79.22
2013	1,327	$86.70
2014 (January – August)	1,173	$95.60
2014 (September – December)	333	$82.72

At June 30, 2012, the aggregate fair value of our commodity derivative contracts was an asset of approximately $591,000.

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 June 30, 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	$2,535	Derivatives – current	$3,456
Interest rate derivatives	Derivatives – current	—	Derivatives – current	602
Commodity price derivatives	Derivatives - noncurrent	2,640	Derivatives - noncurrent	1,128
		$5,175		$5,186

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 June 30, 2012 and December 31, 2011 due to their short term maturities. The following tables set forth information about the Company's assets and liabilities measured at fair value, as of June 30, 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 June 30, 2012
Assets				
Investment in common stock	$67	$—	$ —	$67
NYMEX Fixed Price Derivative contracts	—	5,175	—	5,175
Total Assets	$67	$5,175	$ —	$5,242
Liabilities				
NYMEX Fixed Price Derivative contracts	$—	$4,584	$ —	$4,584
Interest Rate Swaps	—	—	602	602
Total Liabilities	$—	$4,584	$ 602	$5,186

	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 June 30, 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 and six months ended June 30, 2012 are as follows:

	Derivative Assets (Liabilities) - net	
	Three Months Ended June 30, 2012	Six Months Ended June 30, 2012
Balance beginning of period	$(1,106)	$(1,546)
Total realized and unrealized losses included in change in net liability	(79)	(214)
Settlements during the period	583	1,158
Balance June 30, 2012	$(602)	$(602)

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 table provides the Company's geographic operating segment data for the three and six months ended June 30, 2012 and 2011:

	Three Months Ended June 30, 2012			
	U.S	Canada	Corporate	Total
Revenues:				
Oil and gas production	$15,112	$822	$—	$15,934
Other	—	—	4	4
	15,112	822	4	15,938
Expenses (income):				
Lease operating	5,041	341	—	5,382
Production taxes	1,489	—	—	1,489
Depreciation, depletion and amortization	4,896	421	63	5,380
Impairment	—	1,306	—	1,306
General and administrative	377	174	1,853	2,404
Net interest	115	4	1,150	1,269
Amortization of deferred financing fees	—	—	266	266
Equity in income of joint venture	—	—	(1,251)	(1,251)
(Gain) loss on derivative contracts	—	—	(11,210)	(11,210)
Other	—	—	—	—
	11,918	2,246	(9,129)	5,035

Net income (loss)	$3,194	$(1,424)	$9,133	$10,903

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	Three Months Ended June 30, 2011			
	U.S	Canada	Corporate	Total
Revenues:				
Oil and gas production	$16,136	$517	$—	$16,653
Other	—	—	3	3
	16,136	517	3	16,656
Expenses (income):				
Lease operating	5,375	191	—	5,566
Production taxes	1,426	—	—	1,426
Depreciation, depletion and amortization	3,488	229	63	3,780
General and administrative	395	159	1,892	2,446
Net interest	220	1	1,113	1,334
Amortization of deferred financing fees	—	—	770	770
Equity in income of joint venture	—	—	(769)	(769)
Gain on derivative contracts	—	—	(6,846)	(6,846)
Other	—	—	12	12
	10,904	580	(3,765)	7,719
Net income (loss)	$5,232	$(63)	$3,768	$8,937

	Six Months Ended June 30, 2012			
	U.S	Canada	Corporate	Total
Revenues:				
Oil and gas production	$30,987	$1,326	$—	$32,313
Other	—	—	18	18
	30,987	1,326	18	32,331
Expenses (income):				
Lease operating	10,750	566	—	11,316
Production taxes	2,985	—	—	2,985
Depreciation, depletion and amortization	9,454	639	125	10,218
Impairment	—	1,306	—	1,306
General and administrative	703	295	3,307	4,305
Net interest	227—	8	2,228	2,463
Amortization of deferred financing fees	—	—	296	296
Equity in income of joint venture	—	—	(2,034)	(2,034)
Gain on derivative contracts	—	—	(10,286)	(10,286)
Other	—	—	42	42
	24,119	2,814	(6,322)	20,611
Net income (loss)	$6,868	$(1,488)	$6,340	$11,720

	Six Months Ended June 30, 2011			
	U.S	Canada	Corporate	Total
Revenues:				
Oil and gas production	$29,794	$706	$—	$30,500
Other	—	—	4	4
	29,794	706	4	30,504
Expenses (income):				
Lease operating	9,255	326	—	9,581
Production taxes	2,680	—	—	2,680
Depreciation, depletion and amortization	6,761	324	125	7,210
General and administrative	911	378	3,803	5,092
Net interest	220	1	2,716	2,937
Amortization of deferred financing fees	—	—	1,270	1,270
Equity in income of joint venture	—	—	(1,518)	(1,518)
Loss on derivative contracts	—	—	4,247	4,247
Other	—	—	87	87
	19,827	1,029	10,730	31,586
Net income (loss)	$9,967	$(323)	$(10,726)	$(1,082)

The following table provides the Company's geographic asset data as of June 30, 2012 and December 31, 2011:

Segment Assets:	June 30, 2012	December 31, 2011
United States	$185,355	$167,739
Canada	24,346	19,379
Corporate	43,594	54,032
	$253,295	$241,150

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 June 30, 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.

Note 10. Subsequent Events

On August 3, 2012, the Company entered into a letter of intent to dissolve its Blue Eagle (Eagle Ford) joint venture, Blue Eagle Energy LLC. Abraxas and its joint venture partner will split the assets with Abraxas retaining a 100 percent interest in the Eagle Ford and shallower rights in Jourdanton, Atascosa County (4,401 net acres), a 100 percent interest in Yoakum, DeWitt County (1,868 net acres), a 25 percent interest in WyCross, McMullen County (695 net acres), and a 25 percent interest in Nordheim, DeWitt County (944 net acres). The producing wells are currently producing 205 barrels of oil equivalent per day (62 percent oil and 11 percent NGL) net to the interest retained by Abraxas. The proved reserves attributable to the Abraxas interests are approximately 2.4 million barrels of oil equivalent (27 percent oil and 25 percent NGL). The probable reserves attributable to the Abraxas interests are 3.7

million barrels of oil equivalent (54 percent oil and 15 percent NGL). Abraxas will receive a $7 million cash payment along with approximately 35 percent of the working capital in Blue Eagle.

On July 31, 2012 the Company closed on a transaction with a large independent to acquire their interests in jointly owned properties in Ward County, West Texas for $7.2 million less closing adjustments. The transaction adds approximately 240 barrels of oil equivalent production per day and proved developed producing reserves of approximately 1.2 million barrels of oil equivalent. Production and reserves are approximately 95 percent natural gas. Net acres acquired are approximately 2,345.

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 six months ended June 30, 2012, the New York Mercantile (NYMEX) price for West Texas Intermediate crude oil (WTI) averaged $98.13 per barrel as compared to $98.44 per barrel during the six months ended June 30, 2011. NYMEX Henry Hub spot prices for gas averaged $2.36 per MMBtu for the six months ended June 30, 2012 compared to $4.27 for the same period of 2011. Prices closed on June 30, 2012 at $84.96 per Bbl of oil and $2.74 per MMBtu of gas, compared to closing on June 30, 2011 at $95.42 per Bbl of oil and $4.33 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 tables sets forth our average differentials for the three and six months ended June 30, 2012 and 2011:

	Oil - WTI			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Average realized price (1)	$81.66	$96.77	$86.36	$91.21
Average NYMEX price	$93.34	$102.34	$98.13	$98.44
Differential	$(11.68)	$(5.57)	$(11.77)	$(7.23)

	Gas – Henry Hub			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Average realized price (1)	$1.89	$3.88	$2.02	$3.75
Average NYMEX price	$2.29	$4.36	$2.36	$4.27
Differential	$(0.40)	$(0.48)	$(0.34)	$(0.52)

(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 six months ended June 30, 2012, we recognized a realized gain of $2.0 million and an unrealized gain of $8.5 million on our commodity swaps. For the six months ended June 30, 2011, we incurred a realized loss of $65,000 and an unrealized loss of $3.7 million. We have not designated any of these derivative contracts as a hedge as prescribed by applicable accounting rules.

The following table sets forth our derivative contracts at June 30, 2012:

Contract Periods	Fixed Price Swap Oil Daily Volume (Bbl)	Swap Price (per Bbl)
2012 (July – September)	1,176	$78.23
2012 (October – December)	1,509	$79.22
2013	1,327	$86.70
2014 (January – August)	1,173	$95.60
2014 (September – December)	333	$82.72

At June 30, 2012, the aggregate fair value of our commodity derivative contracts was an asset of approximately $591,000.

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 $35.1 million during the six months ended June 30, 2012. We have a capital expenditure budget for 2012 of approximately $70.0 million.Until the earlier of the end of 2012 or until our interest in Blue Eagle is sold, we are required to limit our capital expenditures for drilling and completion expenditures to $10.0 million per quarter, subject to certain pull-back and carry-over provisions;, however, if we maintain a borrowing base availability percentage (defined as the amount available under the credit facility divided by the amount borrowed under the credit facility) of not less than 15% at June 30, 2012 and 10% at September 30, 2012 and December 31, 2012, our capital expenditures in the ordinary course of business are unlimited. At June 30, 2012, our borrowing base availability percentage was 12% and, as a result, we will be subject to this limitation during the quarter ended September 30, 2012, excluding the $7.2 million producing property acquisition that closed on July 31, 2012.

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 June 30, 2012, we had \$15.0 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 leaseholds, 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 may 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 preparing to spud the Jore Federal 2-11 3H in which Abraxas owns an approximate 76 percent working interest, after successfully drilling the Ravin 26-35 2H and Ravin 26-35 3H to total depths in excess of 21,000 feet including approximate 10,000 foot laterals. Abraxas owns an approximate 49 percent working interest in the Ravin wells. These three wells, all located on the same pad, are scheduled to be fraced in late September or early October, with production shortly thereafter.

- Elsewhere in the Bakken/Three Forks play, during the second quarter of 2012, 5 gross (.08 net) non operated wells came on line and at quarter end 1 gross (.01 net) non operated well was completing. Additionally, we have recently agreed to participate in 5 gross (.11 net) wells that have yet to spud.

Rocky Mountain – Wyoming

- In Campbell County, the Hedgehog State 16-2H, a horizontal well in the Turner formation in which we own a 100 percent working interest continues to produce approximately 395 BOEPD (35 percent oil and 13 percent natural gas liquids) with little decline.

West Texas – Spires Ranch

- In a continuation of the horizontal Strawn Lime play initiated by Abraxas several years ago, the Spires Ranch 89 – 1H well is currently drilling the lateral at a measured depth of 7,424 feet toward an objective depth of 10,400 feet including a 3,400 foot lateral section. Abraxas owns a 100 percent working interest in the approximate 5,500 acres Spires Ranch lease.

Canada – Pekisko

- In Alberta, Canada, Canadian Abraxas has six horizontal Pekisko wells on production, although two of which have yet to be fracture stimulated. Due to the recent steep decline on oil prices, the decision was made to postpone significant additional capital expenditures until oil prices improve in the field.

Subsequent Events

On August 3, 2012, The Company entered into a letter of intent to dissolve its Eagle Ford joint venture, Blue Eagle Energy LLC. Abraxas and its joint venture partner will split the assets with Abraxas retaining a 100 percent interest in the Eagle Ford and shallower rights in Jourdanton, Atascosa County (4,401 net acres), a 100 percent interest in Yoakum, DeWitt County (1,868 net acres), a 25 percent interest in WyCross, McMullen County (695 net acres), and a 25 percent interest in Nordheim, DeWitt County (944 net acres). The producing wells are currently producing 205 barrels of oil equivalent per day (62 percent oil and 11 percent NGL) net to the interest retained by Abraxas. The proved reserves attributable to the Abraxas interests are approximately 2.4 million barrels of oil equivalent (27 percent oil and 25 percent NGL). The probable reserves attributable to the Abraxas interests are 3.7 million barrels of oil equivalent (54 percent oil and 15 percent NGL). Abraxas will receive a $7 million cash payment along with our share of the working capital in Blue Eagle.. Abraxas, as operator, and its working interest partner will commence a ten well drilling program utilizing one rig in the WyCross area in the near future. The first well drilled at WyCross, the Abraxas Cobra #1H has produced over 98,000 barrels of oil equivalent since going on production in March of 2012 and is currently flowing approximately 430 barrels of oil equivalent per day (86 percent oil and 5 percent NGL).

On July 31, 2012 the Company closed on a transaction with a large independent to acquire their interests in jointly owned properties in Ward County, West Texas for $7.2 million less closing adjustments. The transaction adds approximately 240 barrels of oil equivalent production per day and proved developed producing reserves of approximately 1.2 million barrels of oil equivalent. Production and reserves are approximately 95 percent natural gas. Net acres acquired are approximately 2,345.

Results of Operations

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Operating revenue:				
Oil sales (1)	$12,897	$12,278	$26,289	$22,163
Gas sales (1)	1,943	4,101	4,005	7,873
NGL sales	1,094	274	2,019	464
Other	4	3	18	4
	$15,938	$16,656	$32,331	$30,504
Operating income (loss)	$(23)	$3,438	$2,201	$5,941
Oil sales (MBbl)	158	127	304	243
Gas sales (MMcf)	1,029	1,058	1,983	2,099
NGL sales (MBbl)	29	5	50	9
BOE sales (MBbl)	359	308	685	602
Average oil sales price ($/Bbl) (1)	$81.66	$96.77	$86.36	$91.21
Average gas sales price ($/Mcf) (1)	$1.89	$3.88	$2.02	$3.75
Average NGL sales price ($/Bbl)	$37.53	$52.28	$40.20	$50.28
Average BOE sales price	$44.44	$54.00	$47.16	$50.66

(1) Before the impact of derivative activities.

Comparison of Three Months Ended June 30, 2012 to Three Months Ended June 30, 2011

Operating Revenue. During the three months ended June 30, 2012, operating revenue decreased to $15.9 million from $16.7 million for the same period of 2011. The decrease in revenue was primarily due to lower realized commodity prices, which was offset by an increase in sales volumes. Decreased commodity prices had a negative impact of $4.1 million while increased sales volumes contributed $3.3 million to operating revenue for the quarter ended June 30, 2012.

Oil sales volumes increased to 158 MBbl during the quarter ended June 30, 2012 from 127 MBbl for the same period of 2011. The increase in oil sales was due to new wells brought on line offset by natural field declines. New wells brought on production contributed 33 MBbl for the three months ended June 30, 2012. Gas sales volumes decreased to 1,029 MMcf for the three months ended June 30, 2012 from 1,058

MMcf for the same period of 2011. The decrease in gas sales was due to natural field declines. NGL sales volumes increased to 29 MBbl for the three months ended June 30, 2012 from 5 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 June 30, 2012 decreased to $5.4 million from $5.6 million for the same period of 2011. LOE per Boe for the three months ended June 30, 2012 was $15.01 compared to $18.05 for the same period of 2011. The decrease per Boe was due to higher sales volumes for the three months ended June 30, 2012 as compared to the same period of 2011.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the three months ended June 30, 2012 increased to $1.5 million from $1.4 million for the same period of 2011, primarily as the result of higher sales volumes.

General and Administrative (“G&A”) Expenses. G&A expenses, excluding stock-based compensation, were $1.7 million for the quarters ended June 30, 2012 and 2011. G&A per Boe was $4.69 for the quarter ended June 30, 2012 compared to $5.64 for the same period of 2011. The decrease per Boe was due to higher production volumes for the three months ended June 30, 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 June 30, 2012 and 2011, stock-based compensation was approximately $722,000 and $706,000, respectively. The increase in 2012 was due to stock option grants in the second quarter of 2012.

Depreciation, Depletion and Amortization (“DD&A”) Expenses. DD&A expense for the three months ended June 30, 2012 increased to $5.4 million from $3.8 million for the same period of 2011. The increase was primarily the result of increased production volumes for the quarter ended June 30, 2012 as compared to the same period of 2011. DD&A per Boe for the three months ended June 30, 2012 was $15.00 compared to $12.26 in 2011.

Ceiling Limitation Write-Down. We record the carrying value of our oil and gas properties using the full cost method of accounting for oil and gas properties. Under this method, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under the full cost accounting rules, the net capitalized cost of oil and gas properties less related deferred taxes, are limited by country, to the lower of the unamortized cost or the cost ceiling, defined as the sum of the present value of estimated unescalated future net revenues from proved reserves, discounted at 10%, plus the cost of properties not being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. If the net capitalized cost of oil and gas properties exceeds the ceiling limit, we are subject to a ceiling limitation write-down to the extent of such excess. A ceiling limitation write-down is a charge to earnings which does not impact cash flow from operating activities. However, such write-downs do impact the amount of our stockholders' equity and reported earnings. As of June 30, 2011, our net capitalized costs of oil and gas properties in the United States and Canada did not exceed the present value of our estimated proved reserves. As of June 30, 2012, the net capitalized cost of our oil and gas properties in Canada exceeded the present value of our estimated proved reserves by $1.3 million, resulting in a write down of $1.3 million.

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

Interest Expense. Interest expense for the three months ended June 30, 2012 and 2011 was $1.3 million. Higher levels of debt for the three months ended June 30, 2012 were offset by lower interest rates.

(Gain) loss on derivative contracts. We account for derivative contract gains and losses based on realized and unrealized amounts. The realized derivative gains or losses are determined by actual derivative settlements during the period. Unrealized gains and losses are based on the periodic mark to market valuation of derivative contracts in place. Our derivative contract transactions do not qualify for hedge accounting as prescribed by ASC 815; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. Our derivative contracts consist of commodity swaps and interest rate swaps. The estimated value of our derivative contracts was a liability of approximately $11,000 as of June 30, 2012, consisting of our commodity derivative contracts at an asset of $591,000 and our interest rate swap at a liability of $602,000. 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 June 30, 2012, we realized a gain on our derivative contracts of $914,000, which included a realized gain of $1.5 million on our commodity swaps and a realized loss of $583,000 on our interest rate swap. For the three months ended June 30, 2012 we incurred an unrealized gain of $10.3 million on our derivative contracts, which included an unrealized gain of $9.8 million on our commodity swaps and an unrealized gain of $505,000 on our interest rate swap. For the three months ended June 30, 2011, we realized a loss on our derivative contracts of $1.1 million, which included a realized loss of $522,000 on our commodity swaps and a realized loss of $591,000 on our interest rate swap. For the three months ended June 30, 2011 we incurred an unrealized gain of $8.0 million on our derivative contracts, which included an unrealized gain of $7.7 million on our commodity swaps and an unrealized gain of $291,000 on our interest rate swap.

Equity in (income) 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 June 30, 2012, our net equity interest in the joint venture's income was $1.3 million. As of June 30, 2012, we owned a 34.7% equity interest in Blue Eagle.

The following table represents our equity interest in Blue Eagle's production for the three months ended June 30, 2012 and 2011:

	Three Months Ended June 30,	
	2012	2011
Oil sales (MBbl)	18	8
Gas sales (MMcf)	47	126
NGL sales (MBbl)	5	12
Average oil sales price ($/Bbl)	$102.33	$93.43
Average gas sales price ($/Mcf)	$2.04	$4.36
Average NGL sales price ($/Bbl)	$33.42	$46.69

Comparison of Six Months Ended June 30, 2012 to Six Months Ended June 30, 2011

Operating Revenue. Operating revenues increased to $32.3 million for the six months ended June 30, 2012 from $30.5 million for the same period of 2011, The increase in revenue was primarily due to higher sales volumes, which was offset by lower commodity prices. Increased sales volumes of oil and NGL's contributed $6.9 million to operating revenues, while lower gas sales volumes had a negative impact of $234,000. Decreased commodity prices had a negative impact of $4.9 million to operating revenue for the six months ended June 30, 2012.

Oil sales volumes increased to 304 MBbl during the six months ended June 30, 2012 from 243 MBbl for the same period of 2011. The increase in oil sales was due to new wells being brought on line offset by natural field declines. New wells contributed 49 MBbl for the six months ended June 30, 2012. Gas sales volumes decreased to 1,983 MMcf for the six months ended June 30, 2012 from 2,099 MMcf for the same period of 2011. The decrease in gas sales was due to natural field declines offset by new wells brought on line. New wells brought onto production contributed 146 MMcf for the six months ended June 30, 2012. NGL sales volumes increased to 50 MBbl for the six months ended

June 30, 2012 from 9 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 six months ended June 30, 2012 increased to $11.3 million from $9.6 million for the same period of 2011. The increase in 2012 was due to an overall increase in the cost of services. LOE per Boe for the six months ended June 30, 2012 was $16.52 compared to $15.91 for the same period of 2011. The increase per Boe was due to higher costs offset by higher sales volumes for the six months ended June 30, 2012 as compared to the same period of 2011.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the six months ended June 30, 2012 increased to $3.0 million from $2.7 million for the same period of 2011. The increase was primarily the result of higher oil sales volumes for the six months ended June 30, 2012 as compared to the same period of 2011.

General and Administrative (“G&A”) Expenses. G&A expenses, excluding stock-based compensation, decreased to $3.1 million for the first six months of 2012 from $4.0 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 six months ended June 30, 2012. G&A per Boe was $4.53 for the six months ended June 30, 2012 compared to $6.68 for the same period of 2011. The decrease per Boe was primarily due to lower costs and higher production volumes in the first six months of 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 six months ended June 30, 2012 and 2011, stock-based compensation was approximately $1.2 million and $1.1 million, respectively. The increase in 2012 was due to stock option grants in the second quarter of 2012.

Depreciation, Depletion and Amortization (“DD&A”) Expenses. DD&A expense for the six months ended June 30, 2012 increased to $10.2 million from $7.2 million for same period of 2011. The increase was primarily the result of increased production volumes as well as increased future development cost in our 2011 year-end reserve report. Our DD&A per Boe for the six months ended June 30, 2012 was $14.91 compared to $11.98 in 2011.

Ceiling Limitation Write-Down. We record the carrying value of our oil and gas properties using the full cost method of accounting for oil and gas properties. Under this method, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under the full cost accounting rules, the net capitalized cost of oil and gas properties less related deferred taxes, are limited by country, to the lower of the unamortized cost or the cost ceiling, defined as the sum of the present value of estimated unescalated future net revenues from proved reserves, discounted at 10%, plus the cost of properties not being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. If the net capitalized cost of oil and gas properties exceeds the ceiling limit, we are subject to a ceiling limitation write-down to the extent of such excess. A ceiling limitation write-down is a charge to earnings which does not impact cash flow from operating activities. However, such write-downs do impact the amount of our stockholders' equity and reported earnings. As of June 30, 2011, our net capitalized costs of oil and gas properties in the United States and Canada did not exceed the present value of our estimated proved reserves. As of June 30, 2012, the net capitalized cost of our oil and gas properties in Canada exceeded the present value of our estimated proved reserves by $1.3 million, resulting in a write down of $1.3 million.

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

Interest Expense. Interest expense for the six months ended June 30, 2012 decreased to $2.5 million from $2.9 million for the same period of 2011. Higher levels of debt for the six months ended June 30, 2012 were offset by lower interest rates.

(Gain) loss on derivative contracts. We account for derivative contract gains and losses based on realized and unrealized amounts. The realized derivative gains or losses are determined by actual derivative settlements during the period. Unrealized gains and losses are based on the periodic mark to market valuation of derivative contracts in place. Our derivative contract transactions do not qualify for hedge accounting as prescribed by ASC 815; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. Our derivative contracts consist of commodity swaps and interest rate swaps. The estimated value of our derivative contracts was a liability of approximately $11,000 as of June 30, 2012, consisting of our commodity derivative contracts at an asset of $591,000 and our interest rate swap at a liability of $602,000. 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 six months ended June 30, 2012, we realized a gain on our derivative contracts of $866,000, which included a realized gain of $2.0 million on our commodity swaps and a realized loss of $1.2 million on our interest rate swap. For the six months ended June 30, 2012 we incurred an unrealized gain of $9.4 million on our derivative contracts, which included an unrealized gain of $8.5 million on our commodity swaps and an unrealized gain of $947,000 on our interest rate swap. For the six months ended June 30, 2011, we realized a loss on our derivative contracts of $1.2 million, which included a realized loss of $65,000 on our commodity swaps and a realized loss of $1.2 million on our interest rate swap and we incurred an unrealized loss of $3.0 million on our derivative contracts, which included an unrealized loss of $3.7 million on our commodity swaps and an unrealized gain of $714,000 on our interest rate swap.

Equity in (income) 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 six months ended June 30, 2012, our net equity interest in the joint venture's income was $2.0 million. As of June 30, 2012, we owned a 34.7% equity interest in Blue Eagle.

The following table represents our equity interest in Blue Eagle's production for the six months ended June 30, 2012 and 2011:

	Six Months Ended June 30,	
	2012	2011
Oil sales (MBbl)	27	15
Gas sales (MMcf)	91	233
NGL sales (MBbl)	8	24
Average oil sales price ($/Bbl)	$104.15	$89.50
Average gas sales price ($/Mcf)	$2.37	$4.21
Average NGL sales price ($/Bbl)	$37.52	$44.92

Recently Issued Accounting Pronouncements

There were no new pronouncements issued during the period ended June 30, 2012 that impact us. All pronouncements impacting the period have been previously disclosed.

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 interests in additional oil and gas properties; and
- production and transportation facilities.

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

Our principal sources of capital going forward will be 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 June 30, 2012, our current liabilities of approximately $31.4 million exceeded our current assets of $14.7 million resulting in a working capital deficit of $16.7 million. This compares to a working capital deficit of approximately $14.8 million at December 31, 2011. Current liabilities at June 30, 2012 primarily consisted of the current portion of derivative liabilities of $4.1 million, trade payables of $18.5 million, revenues due third parties of $7.2 million, and other accrued liabilities of $1.3 million.

Capital expenditures. Capital expenditures during the six months ended June 30, 2012 were $35.1 million compared to $25.6 million during the same period of 2011. The table below sets forth the components of these capital expenditures.

	Six Months Ended June 30,	
	2012	2011
Expenditure category:		
Development	$31,608	$25,422
Facilities and other	3,508	200
Total	$35,116	$25,622

During the six months ended June 30, 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 six months ended June 30, 2011, capital expenditures were primarily for development of our existing oil and gas properties. Our capital budget for 2012 is $70.0 million, however, until the earlier of the end of 2012 or the date that our interest in Blue Eagle is sold, our amended credit facility requires us to limit our capital expenditures for drilling/completion expenditures to $10.0 million per quarter, subject to certain pull-back and carry-over provisions. Capital expenditures in the ordinary course of business are not subject to the $10.0 million limit if we maintain a borrowing base availability percentage (defined as the amount available under the credit facility divided by the amount borrowed under the credit facility) of not less than 15% at June 30, 2012 and 10% at September 30, 2012 and December 31, 2012. At June 30, 2012 our borrowing base availability percentage was 12% and, as a result we will be subject to this limitation during the quarter ending September 30, 2012, excluding the $7.2 million producing property acquisition which closed on July 31, 2012. 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, however conditions are improving. 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:

	Six Months Ended June 30,	
	2012	2011
Net cash provided by operating activities	$25,743	$6,579
Net cash used in investing activities	(35,116)	(17,165)
Net cash provided by financing activities	9,680	14,638
Total	$307	$4,052

Operating activities during the six months ended June 30, 2012 provided $25.7 million of cash compared to providing $6.6 million in the same period in 2011. Net income (loss) plus non-cash expense items during 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 $35.1 million during the six months ended June 30, 2012 compared to using $17.2 million in the same period of 2011. For the first six months of 2012, funds used for capital expenditures were primarily for the development of existing properties and the completion of the refurbishment of our drilling rig. Funds used for capital expenditures for the first six months of 2011 were primarily for the development of our existing properties. Financing activities provided $9.7 million for the first six months of 2012 compared to providing $14.6 million for the first six months of 2011. Funds provided during the six months ended June 30, 2012 were primarily proceeds from borrowings on our long term debt. Funds provided during the six months ended June 30, 2011 were primarily the proceeds from our equity offering in February 2011 of $62.2 million offset by payments on our long term debt of $58.1 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, however conditions are improving. 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. 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.

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 June 30, 2012:

		Payments due in twelve month periods ending:			
Contractual Obligations	Total	June 30, 2013	June 30, 2014-2015	June 30, 2016-2017	Thereafter
Long-term debt (1)	$136,850	$186	$133,200	$3,464	$—
Interest on long-term debt (2)	14,725	4,945	9,649	131	—
Lease obligations (3)	78	52	26	—	—
Total	$151,653	$5,183	$142,875	$3,595	$—

(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 June 30, 2012, our reserve for these obligations totaled $8.7 million for which no contractual commitment exists. For additional information related to this obligation, see Note 1 of the Notes to Condensed Consolidated Financial Statements.

Off-Balance Sheet Arrangements. At June 30, 2012, we had no existing off-balance sheet arrangements, as defined under SEC regulations, that have or are reasonably likely to have a current or future 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 June 30, 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 and borrowings under our credit facilities and other sources. Given our high degree of operating control, the timing and incurrence of operating and capital expenditures is largely within our discretion.

Long-Term Indebtedness

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

	June 30, 2012	December 31, 2011
Credit facility	$125,000	$115,000
Rig loan agreement	7,000	6,500
Real estate lien note	4,850	4,939
	136,850	126,439
Less current maturities	(186)	(181)
	$136,664	$126,258

Credit Facility

On June 29, 2012, we entered into an amendment to our 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 June 30, 2012, $125.0 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 $140.0 million. This amount will remain in effect until the earliest of (a) the sale of our interest in Blue Eagle, (b) the date on which the borrowing base is redetermined based upon our internal engineering report as of June 30, 2012, and (c) October 31, 2012. The borrowing base is determined semi-annually by the lenders based upon our reserve reports, one of which must be prepared by our independent petroleum engineers and one of which may be prepared internally. The amount of the borrowing base is calculated by the lenders based upon their valuation of our Proved reserves securing the facility utilizing these reserve reports and their own internal decisions. In addition, the lenders, in their sole discretion, are able to make one additional borrowing base redetermination during any six-month period between scheduled redeterminations and we are able to request one redetermination during any six-month period between scheduled redeterminations. The borrowing base will be automatically reduced in connection with any sales of producing properties with a market value of 5% or more of our then-current borrowing base and in connection with any hedge termination which could reduce the collateral value by 5% or more. Our borrowing base of $140.0 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 June 30, 2012, the interest rate on the credit facility was 3.50% 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 of not less than 2.50 to 1.00. We are also required to maintain as of the last day of each fiscal quarter a total debt to EBITDAX ratio of not more than 4.00 to 1.00 and, until the earlier of the date we sell our interest in Blue Eagle or December 31, 2012, liquidity (defined as sum of our borrowing base availability, liquid investments and unrestricted cash) of $7.5 million. 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 June 30, 2012, the interest coverage ratio was 7.38 to 1.00, the total debt to EBITDAX ratio was 2.85 to 1.00 our current ratio was 1.09 to 1.0 and we had liquidity of $15.3 million.

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.

In addition, until the earlier of the end of 2012 or the date that our interest in Blue Eagle is sold, we are required to limit our capital expenditures for drilling / completion expenditures to $10.0 million per quarter, subject to certain pull-back and carry-over provisions; however if we maintain a borrowing base availability percentage (defined as the amount available under the credit facility divided by the amount borrowed under the credit facility) of not less than 15% at June 30, 2012 and 10% at September 30, 2012 and December 31, 2012 our capital expenditures in the ordinary course of business are not subject to this limitation. At June 30, 2012, our borrowing base availability percentage was 12 % and, as a result, we are subject to this limitation during the quarter ending September 30, 2012, excluding $7.2 million for the acquisition of producing properties that closed on July 31, 2012. 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 June 30, 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 June 30, 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.

The following table sets forth our derivative contract position as of June 30, 2012:

	Fixed Price Swap Oil	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)
2012 (July – September)	1,176	$78.23
2012 (October – December)	1,509	$79.22
2013	1,327	$86.70
2014 (January – August)	1,173	$95.60
2014 (September – December)	333	$82.72

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 six months ended June 30, 2012, we incurred a realized gain of $2.0 million and an unrealized gain of $8.5 million as compared to a realized loss of $65,000 and an unrealized loss of $3.7 million on our commodity derivative contracts during the first six months 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—Derivative Instrument 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 $8.7 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 six months ended June 30, 2012. The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. As of June 30, 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, have undergone an audit of their 2009 Federal income tax returns. The audit of the Federal income tax return of Abraxas Energy Partners, L.P. was completed with no changes. The audit of Abraxas Petroleum Corporation resulted in a notice of proposed adjustment of $686,000. The Company does not agree with the findings and intends to aggressively appeal the proposed adjustment; however, no assurances can be made that such appeals will be successful.

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Item 3. Quantitative and Qualitative Disclosures about Market Risk.

Commodity Price Risk

As an independent oil and gas producer, our revenue, cash flow from operations, other income and profitability, reserve values, access to capital and future rate of growth are substantially dependent upon the prevailing prices of oil and gas. Declines in commodity prices will adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower commodity prices may reduce the amount of oil and gas that we can produce economically. Prevailing prices for such commodities are subject to wide fluctuation in response to relatively minor changes in supply and demand and a variety of additional factors beyond our control, such as global, political and economic conditions. Historically, prices received for 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 indices 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 six months ended June 30, 2012, a 10% decline in oil and gas prices would have reduced our operating revenue, cash flow and net income by approximately $3.2 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 June 30, 2012:

	Fixed Price Swap Oil	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)
2012 (July – September)	1,176	$78.23
2012 (October – December)	1,509	$79.22
2013	1,327	$86.70
2014 (January – August)	1,173	$95.60
2014 (September – December)	333	$82.72

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 June 30, 2012, the aggregate fair market value of our commodity derivative contracts was an asset of approximately $591,000 million and the aggregate fair market value of our interest rate swap was a liability of approximately $602,000.

For the six months ended June 30, 2012, we recognized a realized gain of $2.0 million and an unrealized gain of $ 8.5 million on our commodity derivative contracts and we recognized a realized loss of $1.2 million and an unrealized gain of $947,000 on our interest rate swap.

Interest rate risk

We are subject to interest rate risk associated with borrowings under our credit facility. As of June 30, 2012, we had $125.0 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 June 30, 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 Accounting 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 six months ended June 30, 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 June 30, 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.

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.

Our sales of oil, natural gas, NGLs and other energy commodities, and related hedging activities, expose us to potential regulatory risks.

The Federal Trade Commission, the Federal Energy Regulatory Commission and the Commodity Futures Trading Commission (the "CFTC") hold statutory authority to monitor certain segments of the physical and futures energy commodities markets. These agencies have proposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales of oil, natural gas, NGLs or other energy commodities, and any related hedging activities that we undertake, we are required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. Our sales may also be subject to certain reporting and other requirements. Failure to comply with such regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations, financial condition.

The July 2010 Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Act") provides for new statutory and regulatory requirements for certain derivative transactions, which are now broadly referred to as "swaps" and which include oil and gas hedging transactions and interest rate swaps. Swaps designated by the CFTC and swaps within certain classes of swaps designated by the CFTC will be required to be submitted for clearing on a derivative clearing organization (a "DCO") and, if accepted for clearing, cleared on the DCO. [Transactions in swaps accepted for clearing must be executed on a board of trade designated as a contract market or a swap execution facility if such swaps are made available for trading on such a board of trade or swap execution facility.] The Act provides an exception from application of the Act's clearing requirement that commercial end-users may elect for swaps they use to hedge or mitigate commercial risks. Although we believe we will be able to elect such exception with respect to most, if not all, of our swaps, if we cannot do so with respect to many of the swaps we enter into, our ability to execute our hedging program efficiently will be adversely affected. In addition, any of our existing swaps, as well as swaps that we enter before such swaps become subject to the clearing requirement, that fall within a class of swaps becoming subject to the clearing requirement will have to be submitted for clearing unless we meet certain reporting requirements.

We anticipate that, under regulations adopted under the Act and relevant DCO and other rules, we will be required to post cash collateral for those of our derivative transactions constituting swaps (including our interest rate swaps and commodities-related swaps) that we ultimately must clear on a DCO. Moreover, the CFTC and the federal regulators of banks and other financial institutions have proposed regulations imposing margin requirements for non-cleared swaps that, if adopted, could require us to post cash or other types of collateral for our non-cleared swaps from time to time in certain circumstances. Posting cash collateral or margin with respect to our swaps could cause liquidity issues for us by reducing our ability to use our cash for capital expenditures or other partnership purposes. A requirement to post cash collateral or margin could therefore reduce our ability to execute strategic hedges to reduce commodity price uncertainty and, thus, to protect cash flows. In addition, even if we are not required to post cash collateral or margin for our swaps, the banks and other derivatives dealers who are the contractual counterparties to our swaps will be required to comply with the Act's new requirements, and the costs of their compliance will likely be passed on to customers, including us, thus increasing our costs of engaging in hedging transactions, decreasing the benefits of those transactions to us and reducing our cash flows.

As required by the Act, the CFTC has also adopted regulations setting limits on the positions that a party may hold for its own account in certain futures contracts and economically equivalent futures contracts, options contracts, swaps and swaptions in a number of physical commodities, including NYMEX contracts relating to light sweet (WTI) crude oil and Henry Hub natural gas. The regulations will allow us to exceed position limits otherwise applicable to us to the extent a contract or swap we hold constitutes a bona fide hedging transaction or position. If for any reason our contracts relating to such commodities, if any, fail to qualify for the exemption from the position limits, our ability to execute strategic hedges to reduce commodity price uncertainty, and, thus, to protect cash flows could be impaired.

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 10.1	Amendment No. 2 to Second Amended and Restated Credit Agreement dated as of June 29, 2012 among the Company, the Guarantors party thereto, the Lenders party thereto and Société Générale, as Administrative Agent
Exhibit 31.1	Certification - Robert L.G. Watson, CEO
Exhibit 31.2	Certification – G. William Krog, CAO
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 – G. William Krog, CAO

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: August 9, 2012	By: /s/Robert L.G. Watson ROBERT L.G. WATSON, President and Principal Executive Officer
Date: August 9, 2012	By: /s/G. William Krog, Jr. G. WILLIAM KROG, JR., Principal Accounting Officer

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