ABRAXAS PETROLEUM CORP
Form 10-Q
August 09, 2011

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, 2011

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 (State of Incorporation)	74-2584033 (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 (Do not mark if a smaller reporting company)	o	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 5, 2011 was 91,799,371 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,” “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 oil and gas 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 and gas equivalents are determined using the ratio of six Mcf of gas to one barrel of oil, condensate or NGL.

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

Terms used to describe quantities of oil and gas:

"Bbl" – barrel or barrels.

"Bcf" – billion cubic feet of gas.

"Bcfe" – billion cubic feet of gas equivalent.

"Boe" – barrels of oil equivalent.

"Boepd" – barrels of oil equivalent per day.

"Bopd" – barrels of oil per day.

"MBbl" – thousand barrels.

"MBoe" – thousand barrels of oil equivalent.

"Mcf" – thousand cubic feet of gas.

"Mcfe" – thousand cubic feet of gas equivalent.

"MMBbl" – million barrels.

"MMBoe" – million barrels of oil equivalent.

"MMBtu" – million British Thermal Units of gas.

"MMcf" – million cubic feet of gas.

"MMcfe" – million cubic feet of gas equivalent.

"MMcfepd" – million cubic feet of gas equivalent per day.

"MMcfpd" – million cubic feet of gas per day.

"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 proved oil or gas reserves.

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

"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 oil or gas 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 deemed to exist when the sum of fractional ownership working interests in gross acres equals one (e.g., a 50% working interest in a lease covering 320 gross acres is equivalent to 160 net acres).

“Net well” is deemed to exist when the sum of fractional ownership working interests in gross wells equals one.

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

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

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

"Proved reserves" or "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 economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

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

"Proved undeveloped drilling location"is a site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

"Proved undeveloped reserves" or "PUD's" 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 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 in accordance with guidelines promulgated by the 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, calculated in accordance with Accounting Standards Codifications ("ASC") 932, "Disclosures About Oil and Gas Producing Activities."

ABRAXAS PETROLEUM CORPORATION

FORM 10 – Q
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PART I
FINANCIAL INFORMATION

Item 1. Financial Statements

Abraxas Petroleum Corporation
Condensed Consolidated Balance Sheets
(in thousands)

	June 30, 2011 (Unaudited)	December 31, 2010
Assets		
Current assets:		
Cash and cash equivalents	$ 4,151	$ 99
Accounts receivable, net:		
Joint owners	1,538	5,145
Oil and gas production	9,151	6,958
Other	298	642
	10,987	12,745
Derivative asset – current	6,964	6,941
Assets held for sale	—	8,457
Other current assets	415	396
Total current assets	22,517	28,638
Property and equipment:		
Oil and gas properties, full cost method of accounting:		
Proved	459,705	434,858
Unproved properties excluded from depletion	1,911	1,085
Other property and equipment	11,742	11,536
Total	473,358	447,479
Less accumulated depreciation, depletion, and amortization	(337,561)	(330,231)
Total property and equipment – net	135,797	117,248
Investment in joint venture	25,545	24,027
Deferred financing fees, net	3,751	3,494
Derivative asset – long-term	6,680	8,674
Other assets	858	828
Total assets	$ 195,148	$ 182,909

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, 2011 (Unaudited)	December 31, 2010
Liabilities and Stockholders' Equity (Deficit)		
Current liabilities:		
Accounts payable	$ 13,549	$ 23,589
Oil and gas production payable	6,847	3,000
Accrued interest	29	277
Other accrued expenses	1,574	779
Derivative liability – current	11,788	9,742
Current maturities of long-term debt	157	152
Total current liabilities	33,944	37,539
Long-term debt, excluding current maturities	94,860	140,940
Derivative liability – long-term	10,752	11,672
Future site restoration	8,077	7,734
Total liabilities	147,633	197,885
Stockholders' Equity (Deficit)		
Preferred stock, par value $.01 per share, authorized 1,000,000 shares; -0- issued and outstanding	—	—
Common stock, par value $.01 per share, authorized 200,000,000 shares;91,740,465 and 76,427,561 issued and outstanding	917	764
Additional paid-in capital	247,523	184,223
Accumulated deficit	(201,290)	(200,208)
Accumulated other comprehensive income	365	245
Total stockholders' equity (deficit)	47,515	(14,976)
Total liabilities and stockholders' equity (deficit)	$ 195,148	$ 182,909

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,	
	2011	2010	2011	2010
Revenue:				
Oil and gas production revenues	$16,653	$14,646	$30,500	$30,509
Rig revenues	297	259	492	520
Other	3	4	4	6
	16,953	14,909	30,996	31,035
Operating costs and expenses:				
Lease operating expenses	5,601	5,040	9,622	9,627
Production taxes	1,426	1,525	2,680	3,227
Depreciation, depletion, and amortization	3,780	4,433	7,210	8,674
Rig operations	262	193	451	390
General and administrative (including stock-based compensation of $706, $537, $1,069 and $847)	2,446	2,191	5,092	4,332
	13,515	13,382	25,055	26,250
Operating income	3,438	1,527	5,941	4,785
Other (income) expense:				
Interest income	(2)	(2)	(4)	(4)
Interest expense	1,336	2,252	2,941	4,586
Amortization of deferred financing fee	770	513	1,270	1,322
(Gain) loss on derivative contracts (unrealized $(7,959), $(5,941), $3,019 and $(17,636))	(6,846)	(6,550)	4,247	(17,527)
Equity in (income) loss of joint venture	(769)	—	(1,518)	—
Other	12	14	87	(75)
	(5,499)	(3,773)	7,023	(11,698)
Net income (loss)	$8,937	$5,300	$(1,082)	$16,483
Net income (loss) per common share – basic	$0.10	$0.07	$(0.01)	$0.22
Net income (loss) per common share – diluted	$0.10	$0.07	$(0.01)	$0.21

See accompanying notes to condensed consolidated financial statements (unaudited)

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

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Operating Activities		
Net (loss) income	$(1,082)	$16,483
Adjustments to reconcile net (loss) income to net cash provided by operating activities:		
Equity in income of joint venture	(1,518)	—
Change in derivative fair value	3,097	(18,477)
Depreciation, depletion, and amortization	7,210	8,674
Amortization of deferred financing fees	1,270	1,322
Accretion of future site restoration	221	271
Stock-based compensation	1,069	847
Other non-cash expenses	—	24
Changes in operating assets and liabilities:		
Accounts receivable	1,770	149
Other	69	(260)
Accounts payable and accrued expenses	(5,527)	(3,285)
Net cash provided by operating activities	6,579	5,748
Investing Activities		
Capital expenditures, including purchases and development of properties	(25,622)	(8,592)
Proceeds from sale of oil and gas properties	8,457	11,008
Net cash (used in) provided by investing activities	(17,165)	2,416
Financing Activities		
Proceeds from long-term borrowings	12,000	2,000
Payments on long-term borrowings	(58,075)	(9,270)
Deferred financing fees	(1,527)	(139)
Proceeds from issuance of common stock	62,224	—
Other	16	(22)
Net cash provided by (used in) financing activities	14,638	(7,431)
Effect of exchange rate changes on cash	—	—
Increase in cash	4,052	733
Cash and equivalents, at beginning of period	99	1,861
Cash and equivalents, at end of period	$4,151	$2,594
Supplemental disclosure of cash flow information:		
Interest paid	$2,968	$4,314

See accompanying notes to condensed consolidated financial statements

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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, 2010 filed with the Securities and Exchange Commission on March 16, 2011. 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 Securities and Exchange Commission. The results of operations and the cash flows for the periods ended June 30, 2011 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, 2010.

Consolidation Principles

The terms "Abraxas," "Abraxas Petroleum," "we," "us," "our" or the "Company" refer to Abraxas Petroleum Corporation ar of its consolidated subsidiaries, including its wholly-owned foreign subsidiary, Canadian Abraxas Petroleum, ULC.

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.

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. For the three and six months ended June 30, 2011 , the Company incurred expenses of $599,000 and $866,000, respectively, and for the three and six months ended June 30, 2010, the Company incurred expenses of $444,000 and $637,000, respectively, in stock-based compensation expense related to stock options.

The following table summarizes the Company’s stock option activity for the six months ended June 30, 2011:

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	Number of Shares	Weighted Average Option Exercise Price Per Share	Weighted Average Grant Date Fair Value Per Share	Aggregate Intrinsic Value
Outstanding, December 31, 2010	4,820	$ 2.23	$ 1.60	$ 6,880
Granted	601	$ 4.64	$ 3.31	1,988
Exercised	(292)	$ 1.81	$ 1.28	(322)
Expired or canceled	(26)	$ 1.83	$ 1.31	(34)
Outstanding, June 30, 2011	5,103	$ 2.53	$ 1.81	$ 8,512

The following table shows the weighted average assumptions used in the Black-Scholes valuation of the fair value of option grants for the six months ended June 30, 2011:

Expected dividend yield	0	%
Volatility	79.58	%
Risk free interest rate	2.48	%
Expected life	6.5	Years
Fair value of options granted (in thousands)	$ 1,988	
Weighted average grant date fair value per share of options granted	$ 3.31	

Additional information related to options at June 30, 2011 and December 31, 2010 is as follows:

	June 30, 2011	December 31, 2010
Options exercisable	2,517	2,288

As of June 30, 2011, there was approximately $3.6 million of unamortized compensation expense related to outstanding options that will be recognized in 2011 through 2015.

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 value of such stock was determined using the market 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, 2011:

	Number of Shares	Weighted Average Grant Date Fair Value Per Share
Unvested, December 31, 2010	400	$2.02
Granted	41	4.69

Vested/Released	(120)	1.83
Forfeited	(1)	2.59
Unvested, June 30, 2011	320	$2.43

For the three and six months ended June 30, 2011, the Company incurred expenses of $107,000 and $203,000, respectively, and for the three and six months ended June 30, 2010, the Company incurred expenses of $93,000 and $210,000, respectively, in stock-based compensation expense related to restricted stock. As of June 30, 2011, there

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was approximately $455,000 of unamortized compensation expense related to outstanding restricted stock that will be recognized in 2011 through 2015.

Warrants

On May 25, 2007, the Company entered into a Securities Purchase Agreement with certain accredited investors pursuant to which the Company issued warrants to purchase 1,174,938 shares of common stock. The warrants expire on May 25, 2012 and are exercisable at a price of $3.83 per share, subject to certain adjustments. No warrants were exercised during the six months ended June 30, 2011 or 2010. As of June 30, 2011, there were 878,000 warrants outstanding.

Oil and Gas Properties

The Company follows the full cost method of accounting for oil and gas properties. Under this method, all direct costs and certain indirect costs associated with acquisition of properties and successful as well as unsuccessful exploration and development activities are capitalized. Depreciation, depletion, and amortization of capitalized oil and gas properties and estimated future development costs, excluding unproved properties, are based on the unit-of-production method based on proved reserves. Net capitalized costs of oil and gas properties, less related deferred taxes, are limited to the lower of unamortized cost or the cost ceiling, defined as the sum of the present value of estimated future net revenues from proved reserves based on unescalated prices discounted at 10 percent, plus the cost of properties not being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. Costs in excess of the present value of estimated future net revenues as discussed above 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.

The estimates of our reserves as of December 31, 2010 are based upon various assumptions about future production levels, prices and costs that may not prove to be correct over time. PV-10 is the estimated present value of the future net revenues from our proved oil and gas reserves before income taxes discounted using a 10% discount rate. In particular, estimates of oil and gas reserves, future net revenue from proved reserves and the PV-10 thereof for our oil and gas properties are based on the assumption that future oil and gas prices remain the same as the twelve month first-day-of-the-month average oil and gas prices for the twelve months ended December 31, 2010. The average realized sales prices used for the estimates were $3.91 per Mcf of gas and $70.72 per Bbl of oil. As of December 31, 2010, the net capitalized costs of our oil and gas properties in the United States did not exceed the present value of our estimated proved reserves; however, the net capitalized costs of our oil and gas properties in Canada exceeded the present value of our estimated proved reserves by $4.8 million, resulting in a write down for the year ended December 31, 2010. As of June 30, 2011, the net capitalized costs of our oil and gas properties in the United States and Canada did not exceed the present value of our estimated proved reserves.

PV-10 is considered a non-GAAP financial measure under SEC regulations because it does not include the effects of future income taxes, as is required in computing the standardized measure of discounted future net cash flows. We believe that PV-10 is an important measure that can be used to evaluate the relative significance of our oil and gas properties and that PV-10 is widely used by securities analysts and investors when evaluating oil and gas companies. Because many factors that are unique to each individual company impact the amount of future income taxes to be paid, the use of a pre-tax measure provides greater comparability of assets when evaluating companies. We believe that most other companies in the oil and gas industry calculate PV-10 on the same basis. PV-10 is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting income taxes.

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.

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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 Accounting Standards Codification (“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, 2011 and the year ended December 31, 2010:

	June 30, 2011	December 31, 2010
Beginning asset retirement obligation	$7,734	$10,326
Settled	(2)	(290)
Revisions	(14)	(83)
New wells placed on production and other	139	64
Deletions related to property disposals	(1)	(2,799)
Accretion expense	221	516
Ending asset retirement obligation	$8,077	$7,734

Working Capital (Deficit)

At June 30, 2011, our current liabilities of approximately $33.9 million exceeded our current assets of $22.5 million resulting in a working capital deficit of $11.4 million. This compares to a working capital deficit of approximately $8.9 million at December 31, 2010. Current liabilities at June 30, 2011 primarily consisted of the current portion of derivative liabilities of $11.8 million, trade payables of $13.5 million, revenues due third parties of $6.8 million, and other accrued liabilities of $1.6 million.

Recently Issued Accounting Pronouncements

In January 2010, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update ("ASU") No. 2010-6, “Improving Disclosures about Fair Value Measurements”. ASU No. 2010-06 amends FASB ASC Topic 820, “Fair Value Measurements and Disclosures,” to require additional information to be disclosed principally regarding Level 3 measurements and transfers to and from Level 1 and 2. In addition, enhanced disclosure is required concerning inputs and valuation techniques used to determine Level 2 and Level 3 measurements. This guidance is generally effective for interim and annual reporting periods beginning after December 15, 2009; however, requirements to disclose separately purchases, sales, issuances, and settlements in the Level 3 reconciliation are effective for fiscal years beginning after December 15, 2010 (and for interim periods within such years). This update did not have a material impact on the Company’s consolidated financial statements.

In June 2011, the FASB issued ASU No. 2011-05, Comprehensive Income (Topic 220): Presentation of Comprehensive Income. This ASU will require companies to present the components of net and comprehensive income in either one or two consecutive financial statements and eliminates the option to present other comprehensive income in the statement of changes in shareholders' equity. This ASU is effective for fiscal years and interim periods within those years, beginning after December 15, 2011. The Company is currently evaluating the potential impact of this adoption on its consolidated financial statements.

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In May 2011, the FASB issued ASU No. 2011-04, Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs. This ASU expands existing disclosure requirements for fair value measurements and provides additional information on how to measure fair value. The Company is required to apply this ASU prospectively for interim and annual periods beginning after December 15, 2011. The Company is currently evaluating the potential impact of this adoption on its consolidated financial statements.

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 in Blue Eagle. Rock Oil committed to contribute an additional $50.0 million to Blue Eagle and upon full funding, Abraxas Petroleum will own a 25% equity interest in Blue Eagle and Rock Oil will own a 75% equity interest in Blue Eagle.

Blue Eagle's subject area encompasses 12 counties across the Eagle Ford Shale play for expected future acreage acquisitions. Abraxas Petroleum operates the wells owned by Blue Eagle and Rock Oil manages 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.

At formation and through June 29, 2011, we owned a non-controlling 50.0% interest in the joint venture. On June 29, 2011, Rock Oil contributed $11.0 million in cash to Blue Eagle to purchase approximately 2,487 net acres in McMullen County, Texas, which reduced our equity interest to approximately 41.0%. As of June 30, 2011, we owned a non-controlling 41.0% interest in the joint venture. We account for the joint venture under the equity method of accounting. Under the equity method of accounting, 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 loss (income) of joint venture." For the three and six months ended June 30, 2011, we reported a gain of $769,000 and $1.5 million, respectively, related to Blue Eagle.

The following table summarizes financial data from Blue Eagle's June 30, 2011 and December 31, 2010 financial statements:

Balance Sheet:	As of June 30, 2011	As of December 31, 2010
Assets:		
Current assets	$14,275	$19,625
Oil and gas properties	53,294	31,753
Other assets	41	45
Total assets	$67,610	$51,423
Liabilities and Member Capital:		
Current liabilities	$5,270	$3,368
Other liabilities	9	—
Member capital	62,331	48,055
Total liabilities and member capital	$67,610	$51,423

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Statement of Operations:	Three Months Ended June 30, 2011	Six Months Ended June 30, 2011
Revenue	$3,758	$6,855
Operating expenses	1,544	3,148
Other (income) expense	(4)	(9)
Net income	$2,218	$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 enacted tax rates and laws that will be in effect when the differences are expected to reverse.

For the three and six months ended June 30, 2011, 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. ASC 740-10 did not have any effect on the Company's financial position or results of operations for the three and six months ended June 30, 2011 and 2010. The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. As of June 30, 2011, the Company did not have any accrued interest or penalties related to uncertain tax positions. The tax years from 2000 through 2010 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 in 2009, are currently undergoing an Internal Revenue Service audit on their 2009 Federal income tax returns.

Note 4. Long-Term Debt

Long-term debt consisted of the following:

	June 30, 2011	December 31, 2010
Credit facility	$90,000	$136,000
Real estate lien note	5,017	5,092
	95,017	141,092
Less current maturities	(157)	(152)
	$94,860	$140,940

Credit Facility

On June 30, 2011, we entered into a second amended and restated senior secured credit facility with Société Générale, as administrative agent and issuing lender, and certain other lenders, which we refer to as the credit facility. As of June 30, 2011, $90.0 million was outstanding under the credit facility.

The credit facility has a maximum commitment of $300.0 million and availability is subject to a borrowing base. The borrowing base is currently $125.0 million and is determined semi-annually by the lenders based upon our reserve reports, one of which must be prepared by our independent petroleum engineers and one of which may be prepared internally. The amount of the borrowing base is calculated by the lenders based upon their valuation of our proved reserves utilizing these reserve reports and their own internal decisions. In addition, the lenders, in their sole discretion, are able to make one additional borrowing base redetermination during any six-month period between scheduled redeterminations and we are able to request one redetermination during any six-month period between scheduled redeterminations. The borrowing base will be automatically reduced in connection with any sales of producing properties with a market value of 5% or more of our then-current borrowing base and in connection with any hedge termination which could reduce the collateral value by 5% or more. Our borrowing base of $125.0

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million was determined based upon our reserve report dated December 31, 2010. 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 (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, 2011, the interest rate on the credit facility was 2.94% based on 1-month LIBOR borrowings.

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 Eurodollar 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.

Under the credit facility, we are subject to customary covenants, including certain financial covenants and reporting requirements. We are required to maintain a current ratio as of the last day of each quarter of not less than 1.00 to 1.00 and an interest coverage ratio as of the last day of each quarter of not less than 2.50 to 1.00. We are also required to maintain a total debt to EBITDAX ratio as of the last day of each quarter of not more than 4.00 to 1.00. The current ratio is defined as the ratio of consolidated current assets to consolidated current liabilities. For the purposes of this calculation, current assets include the portion of the borrowing base which is undrawn but excludes any cash deposited with or at the request of 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 or upon the termination of any hedge contract 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. We were in compliance with all covenants as of June 30, 2011.

As of June 30, 2011, the current ratio was 2.49 to 1.00, the interest coverage ratio was 2.92 to 1.00 and the total debt to EBITDAX ratio was 3.33 to 1.00.

In addition to the foregoing and other customary covenants, the credit facility contains a number of covenants that, among other things, restrict our ability to:

- incur or guarantee additional indebtedness;

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

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- permit a change of control.

The credit facility also contains customary events of default, including nonpayment of principal or interest, violations of covenants, cross default and cross acceleration to certain other indebtedness, bankruptcy and material judgments and liabilities.

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 6.375%, and is payable in monthly installments of principal and interest of $39,754 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, 2011, $5.0 million was outstanding on the note.

Note 5. Income (Loss) Per Share

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Numerator:				
Net income (loss)	$8,937	$5,300	$(1,082)	$16,483
Denominator:				
Denominator for basic income (loss) per share - Weighted-average shares	91,409	75,850	88,653	75,824
Effect of dilutive securities:				
Stock options and warrants	2,097	1,298	—	1,228
Denominator for diluted income (loss) per share - adjusted weighted-average shares and assumed conversions	93,506	77,148	88,653	77,052
Net income (loss) per common share – basic	$0.10	$0.07	$(0.01)	$0.22
Net income (loss) per common share – diluted	$0.10	$0.07	$(0.01)	$0.21

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. As a result, our derivative contract transactions do not qualify for hedge accounting as prescribed by ASC 815; therefore, fluctuations in the market value of our derivative contracts are recognized in earnings during the current period.

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The following table sets forth our derivative contract position as of June 30, 2011:

	Fixed Price Swap			
	Oil		Gas	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (MMBtu)	Swap Price (per MMBtu)
2011	1,035	$76.61	9,580	$6.52
2012	946	$70.89	8,303	$6.77
2013	705	$80.79	5,962	$6.84

At June 30, 2011, the aggregate fair market value of our commodity derivative contracts was a liability of approximately $6.3 million.

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

	June 30, 2011		December 31, 2010	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX-based fixed price derivative contracts	Derivative asset - current	$6,964	Derivative asset - current	$6,941
NYMEX-based fixed price derivative contracts	Derivative asset – long-term	$6,680	Derivative asset – long-term	$8,674
NYMEX-based fixed price derivative contracts	Derivative liability - current	$9,150	Derivative liability - current	$6,394
NYMEX-based fixed price derivative contracts	Derivative liability – long-term	$10,752	Derivative liability – long-term	$11,672
Interest rate swap	Derivative liability - current	$2,638	Derivative liability - current	$3,348

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:

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

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

The following tables present information about the Company's assets and liabilities measured at fair value as of June 30, 2011 and December 31, 2010, and indicates the fair value hierarchy of the valuation 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, 2011
Assets				
Investment in common stock	$177	$—	$ —	$177
NYMEX Fixed Price Derivative contracts	—	13,644	—	13,644
Total Assets	$177	$13,644	$ —	$13,821
Liabilities				
NYMEX Fixed Price Derivative contracts	$—	$19,902	$ —	$19,902
Interest Rate Swaps	—	—	2,638	2,638
Total Liabilities	$—	$19,902	$ 2,638	$22,540

	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, 2010
Assets:				
Investment in common stock	$181	$—	$ —	$181
NYMEX Fixed Price Derivative contracts	—	15,615	—	15,615
Total Assets	$181	$15,615	$ —	$15,796
Liabilities:				
NYMEX Fixed Price Derivative contracts	$—	$18,066	$ —	$18,066
Interest Rate Swaps	—	—	3,348	3,348

Total Liabilities	$—	$18,066	$ 3,348	$21,414

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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, 2011 and December 31, 2010 in US 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, which are not traded on a public exchange. The NYMEX-based fixed price derivative contracts are indexed to NYMEX futures contracts, which are actively traded, for the underlying commodity, and are commonly used in the energy industry. A number of financial institutions and large energy companies act as counter-parties to these type of derivative contracts. As the fair value of these derivative contracts is based on a number of inputs, including contractual volumes and prices stated in each derivative contract, current and future NYMEX commodity prices, and quantitative models that are based upon readily observable market parameters that are actively quoted and can be validated through external sources, we have characterized these derivative contracts as Level 2.

In order to 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%. The interest rate swap was further amended in November 2009 lowering our fixed rate to 2.55% and extending the term through August 12, 2012. As there is no actively traded market for this type of swap and no observable market parameters, these derivative contracts are classified as Level 3.

Additional information for the Company's recurring fair value measurements using significant unobservable inputs (Level 3 inputs) for the three and six months ended June 30, 2011 is as follows:

	Derivative Assets (Liabilities) - net	
	Three Months Ended June 30, 2011	Six Months Ended June 30, 2011
Balance Beginning of period	$(2,897)	$(3,348)
Total realized and unrealized losses included in change in net liability	(300)	(448)
Settlements during the period	559	1,158
Balance June 30, 2011	$(2,638)	$(2,638)

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Note 8. Business Segments

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

	Three Months Ended June 30, 2011			
	U.S	Canada	Corporate	Total
Revenues:				
Oil and gas production	$16,136	$517	$—	$16,653
Rig revenue	297	—	—	297
Other	—	—	3	3
	16,433	517	3	16,953
Expenses (income):				
Lease operating	5,410	191	—	5,601
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
Rig operations	262	—	—	262
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
	11,201	580	(3,765)	8,016
Net income (loss)	$5,232	$(63)	$3,768	$8,937

	Six Months Ended June 30, 2011			
	U.S	Canada	Corporate	Total
Revenues:				
Oil and gas production	$29,794	$706	$—	$30,500
Rig revenue	492	—	—	492
Other	—	—	4	4
	30,286	706	4	30,996
Expenses (income):				
Lease operating	9,296	326	—	9,622
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
Rig operations	451	—	—	451
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
	20,319	1,029	10,730	32,078
Net income (loss)	$9,967	$(323)	$(10,726)	$(1,082)

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The following table provides the Company's geographic asset data as of June 30, 2011 and December 31, 2010:

Segment Assets:	June 30, 2011	December 31, 2010
United States	$139,010	$152,599
Canada	6,484	4,393
Corporate	49,654	25,917
	$195,148	$182,909

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, 2011, 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 July 5, 2011, the Company purchased a used Oilwell 2000 hp diesel electric drilling rig, which will be refurbished and mobilized to the Williston Basin. The rig is owned by, and will be operated by Raven Drilling, LLC, a wholly-owned subsidiary of the Company.

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

The following is a discussion of our financial condition, results of operations, liquidity and capital resources. This discussion should be read in conjunction with our consolidated financial statements and the notes thereto, included in our Annual Report on Form 10-K for the year ended December 31, 2010 filed with the Securities and Exchange Commission on March 16, 2011.

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, 2010.

General

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

During the first six months of 2011, the price of oil increased significantly while the average price of gas decreased from the levels experienced during the first six months of 2010. During the first six months of 2011, the New York Mercantile (NYMEX) price for West Texas Intermediate (WTI) averaged $98.44 per Bbl compared to $78.46 per Bbl for the same period of 2010. NYMEX Henry Hub spot prices for gas

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averaged $4.27 per MMBtu for the first six months of 2011 compared to $4.72 for the same period of 2010. Prices closed on June 30, 2011 at $95.42 per Bbl of oil and $4.28 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; and
- gathering, processing and transportation costs.

During the first six months of 2011, differentials averaged ($7.23) per Bbl of oil and ($0.52) per Mcf of gas as compared to ($7.31) per Bbl of oil and ($0.36) per Mcf of gas during the first six months of 2010. Increases in the differential between the benchmark prices for oil and gas and the wellhead price we receive have in the past and could in the future significantly reduce our revenues and cash flow from operations.

We have entered into hedging arrangements for specified volumes, which equated to approximately 80% of the estimated oil and gas production from our net proved developed producing reserves (as of December 31, 2010) through December 31, 2012 and 67% for 2013. By removing a significant portion of price volatility on our future oil and gas production, we believe we will mitigate, but not eliminate, the potential effects of changing commodity prices on our cash flow from operations for those periods. However, when prevailing market prices are higher than our contract prices, we will not realize increased cash flow 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. In the first six months of 2011, we incurred a realized loss of $65,000 and an unrealized loss of $3.7 million on our commodity swaps. In the first six months of 2010, we recognized a realized gain of $1.0 million and an unrealized gain of $19.0 million on our commodity swaps. We have not designated any of these derivative contracts as a hedge as prescribed by applicable accounting rules.

The following table sets forth our derivative position as of June 30, 2011:

	Fixed Price Swap			
	Oil		Gas	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (MMBtu)	Swap Price (per MMBtu)
2011	1,035	$76.61	9,580	$6.52
2012	946	$70.89	8,303	$6.77
2013	705	$80.79	5,962	$6.84

At June 30, 2011, the aggregate fair market value of our oil and gas derivative contracts was a liability of approximately $6.3 million.

Production Volumes.

Because 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, our reserves and production will decrease. Based on the reserve information set forth in our reserve estimates as of December 31, 2010, the average annual estimated decline rate for our net proved developed producing reserves is 12% 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 $25.6 million during the six months ended June 30, 2011. We have a capital expenditure budget for 2011 of approximately $60.0 million. Approximately 50% of the 2011 budget will be spent on unconventional horizontal oil wells in the Bakken/Three Forks and Niobrara plays in the Rocky Mountain region of the United States and the other 50% will target conventional oil plays in the Permian Basin and onshore Gulf Coast regions of the United States and in the province of Alberta, Canada. The 2011 capital expenditure budget is subject to change depending upon a number of factors, including the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the availability of sufficient capital resources, the results of our exploitation efforts, and our ability to obtain permits for drilling locations. 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 are in short supply. As a result, we have experienced and may in the future experience delays in procuring services for the multi-stage frac jobs that we have planned for our operated wells, which would delay the completion of successfully drilled wells. Our capital expenditures could also include expenditures for the acquisition of producing properties, if such opportunities arise. Additionally, the level of capital expenditures will vary during future periods depending on economic and industry conditions and commodity prices. Should the prices of oil and gas decline and if our costs of operations increase or if our production volumes decrease, our cash flows will decrease which may result in a reduction of the capital expenditure budget. If we decrease our capital expenditure budget, we may not be able to offset oil and gas production decreases caused by natural field declines.

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, 2011, we had $35.0 million of availability under our credit facility.

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, after fees and expenses. We used the net proceeds from the offering to repay indebtedness outstanding 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.

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, 2010, we operated properties accounting for approximately 80% 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 (of which 154 were classified as proved undeveloped at December 31, 2010) on our existing leasehold, the successful development of which we believe could significantly increase our production and proved reserves.

Our future oil and gas production, and therefore our success, is highly dependent upon our ability to find, acquire and develop additional reserves that are profitable to produce. The rate of production from our oil and gas properties and our proved reserves will decline as our reserves are produced unless we acquire additional properties containing proved reserves, conduct successful development and exploration activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves. We cannot assure you that our exploration and development activities will result in increases in our proved reserves. If our proved reserves decline in the future, our production may also decline and, consequently, our cash flow from operations and the amount that we are able to borrow under our credit facility will also decline. In addition, approximately 49% of our estimated proved reserves at December 31, 2010 were undeveloped. By their nature, estimates of undeveloped reserves are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling operations. We may be unable to acquire or develop additional reserves, in which case our results of operations and financial condition could be adversely affected.

Operational Update

Weather Related Downtime

During the second quarter of 2011, We experienced above normal weather related downtime, principally in the Rocky Mountain region due to severe flooding as a result of the extreme winter weather and heavy snowfall, which reduced production during the quarter by approximately 100 Boepd.

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Rocky Mountain – North Dakota / Montana

- In McKenzie County, North Dakota, we drilled the Stenehjem 27-34 1H to a total measured depth of 16,504 feet, including a 5,965 foot lateral in the middle Bakken formation, and completed the well with a 17-stage fracture stimulation. The well was placed on production in late June and in 44 days the well has produced (on a restricted choke) 20,000 barrels of oil, 32.2 MMcf of wellhead gas which yields 2,700 barrels of natural gas liquids and 23.3 MMcf of residue gas for a total of 26,500 barrels of oil equivalent, or an average of 600 barrels of oil equivalent per day. For the past three days, the well averaged 615 barrels of oil equivalent per day on a 21/64-inch choke with 750 psi of flowing pressure. We own a 79% working interest in this well.

- In various counties in North Dakota and Montana, fourteen non-operated horizontal wells, targeting the Bakken or Three Forks formation, in which we own a working interest are currently in progress or recently placed on-line. Seven gross (0.35 net) wells went on production in June or July, three gross (0.08 net) wells have been fracture stimulated and are currently cleaning up, one gross (0.36 net) well is waiting on completion, one gross (0.01 net) well is currently drilling and two gross (0.05 net) wells are waiting on a drilling rig. Since January 2010, we have elected to participate in 19 gross (1.00 net) non-operated wells in the Bakken / Three Forks play.

- In McKenzie County, North Dakota, two gross (0.11 net) non-operated horizontal wells targeting the Mission Canyon have been drilled, completed and are currently waiting on production facilities. Early production testing of these wells has yielded flow rates in excess of 1,000 barrels of oil per day each.

- In early July, we announced the purchase of a drilling rig that is in the process of being refurbished. After completion, the rig will be mobilized to McKenzie County, North Dakota and it is anticipated that the rig will begin drilling on the first pad site in October.

Rocky Mountain – Wyoming

- In Campbell and Niobrara Counties, Wyoming, a two well oil development program is scheduled to begin this fall. One of these horizontal wells will target the Niobrara formation and one will target the Turner formation. We own a 100% working interest in each of these wells.

South Texas – Eagle Ford

- We currently own a 41% equity interest in Blue Eagle, a joint venture between Abraxas and Rock Oil Company, LLC. On June 29, 2011, Rock Oil contributed an additional $11 million to the joint venture and Blue Eagle purchased approximately 2,487 net acres in McMullen County, Texas in the oil window of the play.

- In DeWitt County, Texas, Blue Eagle's first well, the T-Bird 1H, continues to outperform expectations and is currently producing 930 barrels of oil equivalent per day, which is comprised of 185 barrels of condensate, 300 barrels of natural gas liquids and 2.7 MMcf of residue gas. The well has produced approximately 230,000 barrels of oil equivalent during its first 180 days on production. Blue Eagle owns a 100% working interest in this well.

- In DeWitt County, Texas, Blue Eagle participated in a non-operated horizontal well with its 43.9% working interest. The Matejek Gas Unit 1 was drilled to a total measured depth of 17,865 feet, including a 3,600 foot lateral, and completed with a 14-stage fracture stimulation. The well is currently shut-in waiting on pipeline hookup which is expected to be completed later this month.

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In Atascosa County, Texas, the Grass Farms 1H is currently drilling the lateral at a total measured depth of 13,150 feet towards a total measured depth of 13,380 feet, including a 6,000 foot lateral. A fracture stimulation date has been secured for this well in September, a month later than originally anticipated. Blue Eagle owns a 100% working interest in this well.

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West Texas

- In Nolan County, Texas, the Spires 126 2H was drilled to a total measured depth of 9,000 feet, including a 2,000 foot lateral, and completed open hole and un-stimulated. The well was recently placed on-line and during the first 20 days of production, the well averaged 125 barrels of oil equivalent per day, which was comprised of 47 barrels of oil, 46 barrels of natural gas liquids and 210 Mcf of residue gas. We own a 100% working interest in this well.

- In Coke County, Texas, the Sadie #2A was drilled to a total vertical depth of 6,425 feet and is waiting on completion and the Sadie #1B is currently drilling below 4,600 feet towards a total vertical depth of 6,500 feet. These two delineation wells are targeting the Canyon Sands. We own a 100% working interest in these wells.

- In Reeves County, Texas, we previously announced that we had acquired an additional 640 net acres, for a total of approximately 3,000 net acres, in the emerging Wolfbone play. Two wells directly adjacent to our acreage are currently being drilled by the industry.

Canada – Pekisko

- In Alberta, Canada, the Twining 6-11 was drilled to a total measured depth of 8,900 feet, including a 3,025 foot lateral, and is waiting on completion and the Twining 6-12 recently reached total measured depth of 9,150 feet, including a 3,380 foot lateral. These two wells are targeting the Pekisko formation. Canadian Abraxas owns a 100% working interest in each of these wells.

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,	
	2011	2010	2011	2010
Operating revenue:				
Oil sales (1)	$12,278	$9,005	$22,163	$17,783
Gas sales (1)	4,101	5,578	7,873	12,579
NGL sales	274	63	464	147
Rig operations	297	259	492	520
Other	3	4	4	6
	$16,953	$14,909	$30,996	$31,035
Operating income	$3,438	$1,527	$5,941	$4,785
Oil sales (MBbl)	127	128	243	249
Gas sales (MMcf)	1,058	1,444	2,099	2,882
NGL sales (MBbl)	5	2	9	3
Average oil sales price ($/Bbl) (1)	$96.77	$70.60	$91.21	$71.53
Average gas sales price ($/Mcf) (1)	$3.88	$3.86	$3.75	$4.36
Average NGL sales price ($/Bbl)	$52.28	$38.58	$50.28	$43.18

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(1) Before the impact of derivative activities.

Comparison of Three Months Ended June 30, 2011 to Three Months Ended June 30, 2010

Operating Revenue. During the three months ended June 30, 2011, operating revenue increased to $17.0 million from $14.9 million for the same period of 2010. The increase in revenue was primarily due to higher realized commodity prices, which was offset by a decrease in sales volumes. Increased commodity prices contributed $3.4 million to operating revenue while decreased sales volumes had a negative impact of $1.4 million for the quarter ended June 30, 2011.

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Oil sales volumes decreased to 127 MBbl during the quarter ended June 30, 2011 from 128 MBbl for the same period of 2010. The decrease in oil sales was due to sales of non-core properties and natural field declines, which was substantially offset by new wells being brought on line. The divested properties produced 8 MBbl during the second quarter of 2010. New wells brought onto production contributed 20 MBbl for the three months ended June 30, 2011. Gas sales volumes decreased to 1,058 MMcf for the three months ended June 30, 2011 from 1,444 MMcf for the same period of 2010. The decrease in gas sales was due to sales of non-core properties and natural field declines. The divested properties produced 257 MMcf during the second quarter of 2010. New wells brought onto production contributed 27 MMcf for the three months ended June 30, 2011. NGL sales volumes increased to 5 MBbl for the three months ended June 30, 2011 from 2 MBbl for the same period of 2010. 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, 2011 increased to $5.6 million from $5.0 million for the same period in 2010. The increase in LOE was due to higher operating cost offset by LOE related to the properties sold. LOE related to properties sold were $331,000 in the three months ended June 30, 2010. LOE per Boe for the three months ended June 30, 2011 was $18.16 compared to $13.63 for the same period of 2010. The increase per Boe was due to higher cost and lower sales volumes for the three months ended June 30, 2011 as compared to the same period of 2010.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the three months ended June 30, 2011 decreased to $1.4 million from $1.5 million for the same period of 2010, primarily as the result of the sale of non-core properties. Production and ad valorem taxes related to the properties sold were $223,000 in the second quarter of 2010.

General and Administrative ("G&A") Expenses. G&A expenses, excluding stock-based compensation, was $1.7 million for the quarters ended June 30, 2011 and 2010. G&A per Boe was $5.64 for the quarter ended June 30, 2011 compared to $4.47 for the same period of 2010. The increase per Boe was due to lower production volumes in the second quarter of 2011 compared to the same period in 2010.

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 quarters ended June 30, 2011 and 2010, stock-based compensation was approximately $706,000 and $537,000, respectively. The increase in 2011 was due to stock option grants in the second quarter of 2011.

Depreciation, Depletion and Amortization ("DD&A") Expenses. DD&A expense for the three months ended June 30, 2011 decreased to $3.8 million from $4.4 million for the same period of 2010. The decrease was primarily the result of decreased production volumes for the quarter ended June 30, 2011 as compared to the same period of 2010, the contribution of properties to Blue Eagle and the divestiture of non-core properties, offset by an increase to the depletion base from an increase in future development costs as determined by the December 31, 2010 reserve report. DD&A per Boe for the three months ended June 30, 2011 was $12.26 compared to $11.98 in 2010. The increase per Boe was primarily due to a higher depletion rate on our Canadian reserves.

Interest Expense. Interest expense for the three months ended June 30, 2011 decreased to $1.3 million from $2.3 million for the same period of 2010. The decrease for the quarter ended June 30, 2011 was primarily due to lower levels of debt as compared to the same period of 2010, as well as 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 $8.9 million as of June 30, 2011. 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, 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

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swap and 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. For the three months ended June 30, 2010, we realized a gain on our derivative contracts of $609,000, which included a realized gain of $1.2 million on our commodity swaps and a realized loss of $569,000 on our interest rate swap and we incurred an unrealized gain of $5.9 million, which included an unrealized gain of $6.6 million on our commodity swaps and an unrealized loss of $611,000 on our interest rate swap.

Equity in (income) loss of joint venture. On August 18, 2010, Abraxas and its wholly-owned subsidiary, Abraxas Operating, LLC, contributed 8,333 net acres in the Eagle Ford Shale play to 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. Simultaneously, Rock Oil contributed $25.0 million in cash to Blue Eagle for a $25.0 million equity interest in Blue Eagle. Rock Oil committed to contribute an additional $50.0 million to Blue Eagle and upon full funding, Abraxas Petroleum will own a 25% equity interest in Blue Eagle and Rock Oil will own a 75% equity interest in Blue Eagle.

At formation and through June 29, 2011, we owned a non-controlling 50.0% interest in the Blue Eagle joint venture. On June 29, 2011, Rock Oil contributed $11.0 million in cash to Blue Eagle to purchase approximately 2,487 net acres in McMullen County, Texas, which reduced our equity interest to approximately 41.0%. For the three months ended June 30, 2011, we reported a gain of $769,000 related to Blue Eagle. See Note 2 of the Notes to Condensed Consolidated Financial Statements.

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

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

Comparison of Six Months Ended June 30, 2011 to Six Months Ended June 30, 2010

Operating Revenue. Operating revenues were $31.0 million for both the six months ended June 30, 2011 and 2010 as higher realized prices offset a decrease in sales volumes. Increased commodity prices contributed $3.1 million to operating revenue while decreased sales volumes had a negative impact of $3.1 million for the six months ended June 30, 2011 compared to 2010.

Oil sales volumes decreased to 243 MBbl during the six months ended June 30, 2011 from 249 MBbl for the same period of 2010. The decrease in oil sales was due to sales of non-core properties and natural field declines offset by new wells being brought on line. The divested properties produced 18 MBbl during the first six months of 2010. New wells brought onto production contributed 35 MBbl for the six months ended June 30, 2011. Gas sales volumes decreased to 2,099 MMcf for the six months ended June 30, 2011 from 2,882 MMcf for the same period of 2010. The decrease in gas sales was due to sales of non-core properties and natural field declines. The divested properties produced 470 MMcf during the first six months of 2010. New wells brought onto production contributed 47 MMcf for the six months ended June 30, 2011. NGL sales volumes increased to 9 MBbl for the six months ended June 30, 2011 from 3 MBbl for the same period of 2010. 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, 2011 and 2010 was $9.6 million. LOE increases were offset by the LOE related to the properties sold. LOE related to properties sold were $779,000 in the six months ended June 30, 2010 and the increase in 2011 was due to an overall increase in the cost of services. LOE per Boe for the six months ended June 30, 2011 was $15.98

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compared to $13.14 for the same period of 2010. The increase per Boe was due to lower sales volumes for the six months ended June 30, 2011 as compared to the same period of 2010.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the six months ended June 30, 2011 decreased to $2.7 million from $3.2 million for the same period of 2010, primarily as the result of the sale of non-core properties. Production and ad valorem taxes related to the properties sold were $428,000 for the six months ended June 30, 2010.

General and Administrative ("G&A") Expenses. G&A expenses, excluding stock-based compensation, increased to $4.0 million for the first six months of 2011 from $3.5 million for the same period of 2010. The increase in G&A was primarily due to additional bonuses paid in 2011 relating to 2010. G&A per Boe was $6.68 for the six months ended June 30, 2011 compared to $4.76 for the same period of 2010. The increase per Boe was primarily due to higher bonuses and lower production volumes in the first six months of 2011 compared to the same period in 2010.

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, 2011 and 2010, stock-based compensation was approximately $1.1 million and $847,000, respectively. The increase in 2011 was due to stock option grants in the second quarter of 2011.

Depreciation, Depletion and Amortization ("DD&A") Expenses. DD&A expense for the six months ended June 30, 2011 decreased to $7.2 million from $8.7 million for same period of 2010. The decrease was primarily the result of decreased production volumes for the six months ended June 30, 2011 as compared to the same period of 2010, the contribution of properties to Blue Eagle and the divestiture of non-core properties, which were offset by an increase to the depletion base from an increase in future development costs as determined by the December 31, 2010 reserve report. Our DD&A per Boe for the six months ended June 30, 2011 was $11.98 compared to $11.84 in 2010. The increase per Boe was primarily due to a higher depletion rate on our Canadian reserves.

Interest Expense. Interest expense for the six months ended June 30, 2011 decreased to $2.9 million from $4.6 million for the same period of 2010. The decrease for the six months ended June 30, 2011 was primarily due to lower levels of debt as compared to the same period of 2010, as well as 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 $8.9 million as of June 30, 2011. 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, 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. For the six months ended June 30, 2010, we realized a loss on our derivative contracts of $109,000, which included a realized gain of $1.0 million on our commodity swaps and a realized loss of $1.1 million on our interest rate swap and we incurred an unrealized gain of $17.6 million, which included an unrealized gain of $19.0 million on our commodity swaps and an unrealized loss of $1.4 million on our interest rate swap.

Equity in (income) loss of joint venture. At formation and through June 29, 2011, we owned a non-controlling 50.0% interest in the Blue Eagle joint venture. On June 29, 2011, Rock Oil contributed $11.0 million in cash to Blue Eagle to purchase approximately 2,487 net acres in McMullen County, Texas, which reduced our equity interest to approximately 41.0%. For the six months ended June 30, 2011, we reported a gain of $1.5 million related to Blue Eagle. See Note 2 of the Notes to Condensed Consolidated Financial Statements.

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

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

Recently Issued Accounting Pronouncements

We discuss recently adopted and issued accounting standards in Item 1. Notes to Condensed Consolidated Financial Statements—Note 1, "Basis of Presentation."

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, 2011, our current liabilities of approximately $33.9 million exceeded our current assets of $22.5 million resulting in a working capital deficit of $11.4 million. This compares to a working capital deficit of approximately $8.9 million at December 31, 2010. Current liabilities at June 30, 2011 primarily consisted of the current portion of derivative liabilities of $11.8 million, trade payables of $13.5 million, revenues due third parties of $6.8 million, and other accrued liabilities of $1.6 million.

Capital expenditures. Capital expenditures during the six months ended June 30, 2011 were $25.6 million compared to $8.6 million during the same period of 2010. The table below sets forth the components of these capital expenditures.

Six Months Ended
June 30,

	2011	2010
Expenditure category:		
Development	$25,422	$8,423
Facilities and other	200	169
Total	$25,622	$8,592

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During the six months ended June 30, 2011 and 2010, capital expenditures were primarily for development of our existing oil and gas properties. We anticipate making capital expenditures in 2011 of $60.0 million. The 2011 capital expenditure budget is subject to change depending upon a number of factors, including the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the availability of sufficient capital resources, the results of our exploitation efforts, and 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 are in short supply. As a result, we have experienced and may in the future experience delays in procuring services for the multi-stage frac jobs that we have planned for our operated wells, which would delay the completion of successfully drilled wells. Our capital expenditures could also include expenditures for the acquisition of producing properties, if such opportunities arise. Additionally, the level of capital expenditures will vary during future periods depending on economic and industry conditions and commodity prices. Should the prices of oil and gas decline and if our costs of operations increase or if our production volumes decrease, our cash flows will decrease which may result in a reduction of the capital expenditure budget. If we decrease our capital expenditure budget, we may not be able to offset oil and gas production decreases caused by natural field declines.

On July 5, 2011, the Company purchased a used Oilwell 2000 hp diesel electric drilling rig, which will be refurbished and mobilized to the Williston Basin.

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,	
	2011	2010
Net cash provided by operating activities	$6,579	$5,748
Net cash (used in) provided by investing activities	(17,165)	2,416
Net cash provided by (used in) financing activities	14,638	(7,431)
Total	$4,052	$733

Operating activities during the six months ended June 30, 2011 provided $6.6 million compared to providing $5.7 million in the same period in 2010. Net income (loss) plus non-cash expense items during 2011 and 2010 and net changes in operating assets and liabilities accounted for most of these funds. Investing activities used $17.2 million during the six months ended June 30, 2011 compared to providing $2.4 million in the same period of 2010. For the first six months of 2011, funds used for capital expenditures were primarily for the development of existing properties. Funds provided for the first six months of 2010 were proceeds from the sale of non-core properties offset by expenditures for the development of our existing properties. Financing activities provided $14.6 million for the first six months of 2011 compared to using $7.4 million for the first six months of 2010. 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.

In the fourth quarter of 2009 and throughout 2010, we sold certain non-operated, non-core assets, to generate cash for debt repayment and to accelerate our drilling program. We sold properties in nine different states for combined net proceeds of approximately $32.2 million (of which $8.5 million was received in February 2011) at various property auctions to numerous buyers. The net proceeds were used to repay outstanding indebtedness under our credit facility, for capital expenditures and general corporate purposes.

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, after estimated fees and expenses. We used the net proceeds from the offering to repay indebtedness outstanding 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.

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Cash from operating activities is dependent upon commodity prices and production volumes. Oil and gas prices are volatile. Oil prices increased during 2010 and have continued to increase during the first six months of 2011, while gas prices remain weak. A decrease in commodity prices from current levels would 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 will decline as reserves are produced. In the future we may sell producing properties, which would 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 any given frac job, frac crews and equipment are in short supply. As a result, we have experienced and may in the future experience delays in procuring services for the multi-stage frac jobs that we have planned for our operated wells, which would delay the completion of successfully drilled wells. 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 49% of our total estimated proved reserves at December 31, 2010 were classified as undeveloped.

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, 2011:

		Payments due in twelve month periods ending:			
Contractual Obligations	Total	June 30, 2012	June 30, 2013-2014	June 30, 2015-2016	Thereafter
Long-term debt (1)	$95,017	$157	$348	$94,512	$—
Interest on long-term debt (2)	11,741	2,961	5,890	2,890	—
Lease obligations (3)	119	46	73	—	—
Total	$106,877	$3,164	$6,311	$97,402	$—

(1) These amounts represent the balances outstanding under our credit facility 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 30, 2014.

We maintain a reserve for cost associated with the retirement of tangible long-lived assets. At June 30, 2011, our reserve for these obligations totaled $8.1 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, 2011, 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, 2011, 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.

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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

Long-term debt consisted of the following:

	June 30, 2011	December 31, 2010
Credit facility	$90,000	$136,000
Real estate lien note	5,017	5,092
	95,017	141,092
Less current maturities	(157)	(152)
	$94,860	$140,940

Credit Facility

On June 30, 2011, we entered into a second amended and restated senior secured credit facility with Société Générale, as administrative agent and issuing lender, and certain other lenders, which we refer to as the credit facility. As of June 30, 2011, $90.0 million was outstanding under the credit facility.

The credit facility has a maximum commitment of $300.0 million and availability is subject to a borrowing base. The borrowing base is currently $125.0 million and is determined semi-annually by the lenders based upon our reserve reports, one of which must be prepared by our independent petroleum engineers and one of which may be prepared internally. The amount of the borrowing base is calculated by the lenders based upon their valuation of our proved reserves utilizing these reserve reports and their own internal decisions. In addition, the lenders, in their sole discretion, are able to make one additional borrowing base redetermination during any six-month period between scheduled redeterminations and we are able to request one redetermination during any six-month period between scheduled redeterminations. The borrowing base will be automatically reduced in connection with any sales of producing properties with a market value of 5% or more of our then-current borrowing base and in connection with any hedge termination which could reduce the collateral value by 5% or more. Our borrowing base of $125.0 million was determined based upon our reserve report dated December 31, 2010. 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, 2011, the interest rate on the credit facility was 2.94% based on 1-month LIBOR borrowings.

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 Eurodollar 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.

Under the credit facility, we are subject to customary covenants, including certain financial covenants and reporting requirements. We are required to maintain a current ratio as of the last day of each quarter of not less than 1.00 to 1.00 and an interest coverage ratio as of the last day of each quarter of not less than 2.50 to 1.00. We are also required to maintain a total debt to EBITDAX ratio as of the last day of each quarter of not more than 4.00 to 1.00. The current ratio is defined as the ratio of consolidated current assets to consolidated current liabilities. For the purposes of this calculation, current assets include the portion of the borrowing base which is undrawn but excludes any cash deposited with or at the request of a counter-party to a hedging arrangement and any assets representing a valuation

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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 or upon the termination of any hedge contract 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. We were in compliance with all covenants as of June 30, 2011.

As of June 30, 2011, the current ratio was 2.49 to 1.00, the interest coverage ratio was 2.92 to 1.00 and total debt to EBITDAX ratio was 3.33 to 1.00.

In addition to the foregoing and other customary covenants, the credit facility contains a number of covenants that, among other things, restrict our ability to:

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

The credit facility also contains customary events of default, including nonpayment of principal or interest, violations of covenants, cross default and cross acceleration to certain other indebtedness, bankruptcy and material judgments and liabilities.

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 6.375%, and is payable in monthly installments of principal and interest of $39,754 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, 2011, $5.0 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. We have entered into commodity swaps on approximately 80% of our estimated oil and gas production from our net proved developed producing reserves (as of December 31, 2010) through December 31, 2012 and on 67% for the calendar year 2013.

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The following table sets forth our derivative contract position as of June 30, 2011:

	Fixed-Price Swaps			
	Oil		Gas	
Contract Period	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (MMBtu)	Swap Price (per MMBtu)
2011	1,035	$76.61	9,580	$6.52
2012	946	$70.89	8,303	$6.77
2013	705	$80.79	5,962	$6.84

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, 2011, we incurred a realized loss of $65,000 and an unrealized loss of $3.7 million as compared to a realized gain of $1.0 million and an unrealized gain of $19.0 million on our commodity derivative contracts during the first six months of 2010. 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, 2010, we had, subject to the limitation discussed below, $141.8 million of net operating loss carryforwards for U.S. tax purposes and $1.1 million of net operating loss carryforwards for Canadian tax purposes. The U.S. loss carryforward will expire from 2022 through 2030 and the Canadian loss carryforward will expire in 2030, 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 established a valuation allowance of $91.9 million for deferred tax assets at December 31, 2010.

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, 2010 or for the six months ended June 30, 2011. The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. As of June 30, 2011, the Company did not have any accrued interest or penalties related to uncertain tax positions. The tax years from 2000 through 2010 remain open to examination by the tax jurisdictions to which the Company is subject. The Company and Abraxas Energy Partners, L.P., which was merged into a wholly-owned subsidiary of Abraxas, are currently undergoing an Internal Revenue Service audit on their 2009 Federal income tax returns.

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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, 2011, a 10% decline in oil and gas prices would have reduced our operating revenue, cash flow and net income by approximately $3.0 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. Our derivative contracts do not qualify for hedge accounting as prescribed by ASC 815; therefore fluctuations in the market value of our derivative contracts are recognized in earnings during the current period.

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.

The following table sets forth our derivative contract position as of June 30, 2011:

	Fixed-Price Swaps			
	Oil		Gas	
Contract Period	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (MMBtu)	Swap Price (per MMBtu)
2011	1,035	$76.61	9,580	$6.52
2012	946	$70.89	8,303	$6.77
2013	705	$80.79	5,962	$6.84

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 expired on August 12, 2010. The interest rate swap was amended in February 2009 lowering our fixed rate to 2.95%. The interest rate swap was further amended in November 2009 lowering our fixed rate to 2.55% and extending the term through August 12, 2012.

At June 30, 2011, the aggregate fair market value of our commodity derivative contracts was a liability of approximately $6.3 million and the aggregate fair market value of our interest rate swap was a liability of approximately $2.6 million.

For the six months ended June 30, 2011, we recognized a realized loss of $65,000 and an unrealized loss of $3.7 million on our commodity derivative contracts and we recognized a realized loss of $1.2 million and an unrealized gain of $714,000 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, 2011, we had $90.0 million of outstanding indebtedness under our credit facility. Outstanding amounts under the credit facility bear interest at (a) the greater of (1) the reference rate announced from time to time by Société Générale, (2) the Federal Funds Rate plus 0.5%, and (3) a rate determined by Société Générale as the daily one-month LIBOR plus, in each case, (b) 1.25—2.25%, depending on the utilization of the borrowing base, or, if we elect LIBOR plus 2.25%—3.25%, depending on the utilization of

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the borrowing base. At June 30, 2011, the interest rate on the credit facility was 2.94% based on 1-month LIBOR borrowings. For every percentage point that the LIBOR rate rises, our interest expense would increase by approximately $900,000 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 expired on August 12, 2010. The interest rate swap was amended in February 2009 lowering our fixed rate to 2.95%. The interest rate swap was further amended in November 2009 lowering our fixed rate to 2.55% and extending the term through August 12, 2012.

Item 4. Controls and Procedures.

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

There were no changes in our internal controls over financial reporting during the three months ended June 30, 2011 covered by this report that could materially affect, or are reasonably likely to materially affect, our financial reporting.

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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, 2011, the Company was not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on its operations.

Item 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, 2010, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K are not the only risks facing Abraxas. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

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

None

Item 3. Defaults Upon Senior Securities.

None

Item 4. [Removed and Reserved].

Item 5. Other Information.

None

Item 6. Exhibits.

(a) Exhibits

Exhibit 31.1	Certification - Robert L.G. Watson, CEO
Exhibit 31.2	Certification – Chris E. Williford, CFO
Exhibit 32.1	Certification pursuant to 18 U.S.C. Section 1350 – Robert L.G. Watson, CEO
	Certification pursuant to 18 U.S.C. Section 1350 – Chris E. Williford, CFO

Exhibit
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ABRAXAS PETROLEUM CORPORATION

SIGNATURES

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

Date: August 9, 2011	By: /s/Robert L.G. Watson ROBERT L.G. WATSON, President and Chief Executive Officer
Date: August 9, 2011	By: /s/Chris E, Williford CHRIS E. WILLIFORD, Executive Vice President and Principal Accounting Officer