

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

FORM 10-Q

(Mark One)

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2009

or

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: 001-14837

Quicksilver Resources Inc.

(Exact name of registrant as specified in its charter)

Delaware

(State or other jurisdiction of
incorporation or organization)

75-2756163

(I.R.S. Employer Identification No.)

777 West Rosedale, Fort Worth, Texas
(Address of principal executive offices)

76104
(Zip Code)

(817) 665-5000

(Registrant's telephone number, including area code)

None

(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 such filing requirements for at least the past 90 days. Yes No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 if Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such file). Yes No

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

Large accelerated filer Accelerated filer Non-accelerated filer Smaller reporting company
(do not check if a smaller reporting company)

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date:

Title of Class

Outstanding as of April 30, 2009

Common Stock, \$0.01 par value

169,020,040

QUICKSILVER RESOURCES INC.
INDEX TO FORM 10-Q
For the Period Ending March 31, 2009

	<u>Page</u>
<u>PART I. FINANCIAL INFORMATION</u>	
<u>Item 1. Financial Statements (Unaudited)</u>	
<u>Condensed Consolidated Statements of Income (Loss) and Comprehensive Loss</u>	5
<u>Condensed Consolidated Balance Sheets</u>	6
<u>Condensed Consolidated Statements of Stockholders' Equity</u>	7
<u>Condensed Consolidated Statements of Cash Flows</u>	8
<u>Notes to Condensed Consolidated Interim Financial Statements</u>	9
<u>Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations</u>	25
<u>Item 3. Quantitative and Qualitative Disclosures About Market Risk</u>	33
<u>Item 4. Controls and Procedures</u>	35
<u>PART II. OTHER INFORMATION</u>	
<u>Item 1. Legal Proceedings</u>	36
<u>Item 1A. Risk Factors</u>	36
<u>Item 2. Unregistered Sales of Equity Securities and Use of Proceeds</u>	49
<u>Item 3. Defaults Upon Senior Securities</u>	50
<u>Item 4. Submission of Matters to a Vote of Security Holders</u>	50
<u>Item 5. Other Information</u>	50
<u>Item 6. Exhibits</u>	50
<u>Signatures</u>	51

Except as otherwise specified and unless the context otherwise requires, references to the "Company," "Quicksilver," "we," "us," and "our" refer to Quicksilver Resources Inc. and its subsidiaries.

DEFINITIONS

As used in this quarterly report unless the context otherwise requires:

- “**AECO**” is a reference, in dollars per MMBtu, for gas delivered onto the NOVA Gas Transmission Ltd. System in Alberta, Canada
- “**Bbl**” or “**Bbls**” means barrel or barrels
- “**Bbld**” means barrel or barrels per day
- “**Bcf**” means billion cubic feet
- “**Bcfd**” means billion cubic feet per day
- “**Bcfe**” means Bcf of natural gas equivalents, calculated as one Bbl of oil or NGLs equaling six Mcf of gas
- “**Btu**” means British Thermal Units, a measure of heating value
- “**Canada**” means the division of Quicksilver encompassing oil and natural gas properties located in Canada
- “**CBM**” means coalbed methane
- “**DD&A**” means Depletion, Depreciation and Accretion
- “**Domestic**” means the properties of Quicksilver in the continental United States
- “**LIBOR**” means London Interbank Offered Rate
- “**MBbl**” or “**MBbls**” means thousand barrels
- “**MBbld**” means thousand barrels per day
- “**MMBbls**” means million barrels
- “**MMBtu**” means million Btu and is approximately equal to 1 Mcf of natural gas
- “**MMBtud**” means million Btu per day
- “**Mcf**” means thousand cubic feet
- “**Mcfe**” means Mcf natural gas equivalents calculated as one Bbl of oil or NGLs equaling six Mcf of gas
- “**MMcf**” means million cubic feet
- “**MMcfd**” means million cubic feet per day
- “**MMcfe**” means MMcf of natural gas equivalents, calculated as one Bbl of oil or NGLs equaling six Mcf of gas
- “**MMcfd**” means MMcf of natural gas equivalents per day, calculated as one Bbl of oil or NGLs equaling six Mcf of gas
- “**NGL**” or “**NGLs**” means natural gas liquids
- “**NYMEX**” means New York Mercantile Exchange
- “**Oil**” includes crude oil and condensate
- “**Tcf**” means trillion cubic feet
- “**Tcfe**” means Tcf of natural gas equivalents, calculated as one Bbl of oil or NGLs equaling six Mcf of gas

COMMONLY USED TERMS

Other commonly used terms and abbreviations include:

- “**ABR**” means adjusted base rate
- “**AOCI**” means accumulated other comprehensive income
- “**Alliance Acquisition**” means the August 8, 2008 purchase of leasehold, royalty and midstream assets in the Barnett Shale in northern Tarrant and southern Denton counties of Texas
- “**BBEP**” means BreitBurn Energy Partners L.P.
- “**BreitBurn Transaction**” means the November 1, 2007 conveyance of our Northeast Operations in exchange for aggregate proceeds of \$1.47 billion
- “**FASB**” means the Financial Accounting Standards Board, which promulgates accounting standards in the U.S.
- “**GAAP**” means accounting principles generally accepted in the United States
- “**IPO**” means the KGS initial public offering completed on August 10, 2007
- “**KGS**” means Quicksilver Gas Services LP, which is our publicly-traded partnership and trades under the ticker symbol “KGS”
- “**Mercury**” means Mercury Exploration Company, which is owned by members of the Darden family
- “**Michigan Sales Contract**” means the gas supply contract which terminates in March 2009 under which we agreed to deliver 25 MMcfd at a floor price of \$2.49 per Mcf
- “**Northeast Operations**” means the oil and gas properties and facilities in Michigan, Indiana and Kentucky which were conveyed to BreitBurn Operating, L.P. on November 1, 2007
- “**OCI**” means other comprehensive income
- “**PCAOB**” means the Public Company Accounting Oversight Board
- “**RSU**” means restricted stock unit
- “**SEC**” means the United States Securities and Exchange Commission
- “**SFAS**” means Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board

Forward-Looking Information

Certain statements contained in this report and other materials we file with the SEC, or in other written or oral statements made or to be made by us, other than statements of historical fact, are “forward-looking statements” as defined in the Private Securities Litigation Reform Act of 1995. Forward-looking statements give our current expectations or forecasts of future events. Words such as “may,” “assume,” “forecast,” “position,” “predict,” “strategy,” “expect,” “intend,” “plan,” “estimate,” “anticipate,” “believe,” “project,” “budget,” “potential,” or “continue,” and similar expressions are used to identify forward-looking statements. They can be affected by assumptions used or by known or unknown risks or uncertainties. Consequently, no forward-looking statements can be guaranteed. Actual results may vary materially. You are cautioned not to place undue reliance on any forward-looking statements. You should also understand that it is not possible to predict or identify all such factors and should not consider the following list to be a complete statement of all potential risks and uncertainties. Factors that could cause our actual results to differ materially from the results contemplated by such forward-looking statements include:

- changes in general economic conditions;
- fluctuations in natural gas, NGL and crude oil prices;
- failure or delays in achieving expected production from exploration and development projects;
- uncertainties inherent in estimates of natural gas, NGL and crude oil reserves and predicting natural gas, NGL and crude oil reservoir performance;
- effects of hedging natural gas, NGL and crude oil prices;
- fluctuations in the value of certain of our assets and liabilities;
- competitive conditions in our industry;
- actions taken or non-performance by third parties, including suppliers, contractors operators, processors, transporters, customers and counterparties;
- changes in the availability and cost of capital;
- delays in obtaining oilfield equipment and increases in drilling and other service costs;
- operating hazards, natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- the effects of existing and future laws and governmental regulations;
- the effects of existing or future litigation; and
- certain factors discussed elsewhere in this quarterly report.

This list of factors is not exhaustive, and new factors may emerge or changes to these factors may occur that would impact our business. Additional information regarding these and other factors may be contained in our filings with the SEC, especially on Forms 10-K, 10-Q and 8-K. All such risk factors are difficult to predict, and are subject to material uncertainties that may affect actual results and may be beyond our control.

All forward-looking statements are expressly qualified in their entirety by the foregoing cautionary statements.

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements (Unaudited)

QUICKSILVER RESOURCES INC.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE LOSS
In thousands, except for per share data — Unaudited

	For the Three Months Ended March 31,	
	2009	2008
Revenue		
Natural gas, NGL and crude oil	\$ 183,554	\$ 158,356
Other	2,378	(739)
Total revenue	<u>185,932</u>	<u>157,617</u>
Operating expenses		
Oil and gas production expense	32,734	32,530
Production and ad valorem taxes	4,366	2,659
Other operating costs	964	1,231
Depletion, depreciation and accretion	59,696	35,059
General and administrative	17,381	15,415
Total expenses	<u>115,141</u>	<u>86,894</u>
Impairment related to oil and gas properties	<u>(896,483)</u>	<u>—</u>
Operating income (loss)	(825,692)	70,723
Income from earnings of BBEP, net	—	6,219
Other income — net	761	1,486
Interest expense	<u>(40,201)</u>	<u>(13,435)</u>
Income (loss) before income taxes	(865,132)	64,993
Income tax (expense) benefit	<u>297,823</u>	<u>(23,351)</u>
Net income (loss)	(567,309)	41,642
Net income attributable to noncontrolling interests	<u>(1,670)</u>	<u>(508)</u>
Net income (loss) attributable to Quicksilver	<u>\$(568,979)</u>	<u>\$ 41,134</u>
Other comprehensive income (loss) — net of income tax		
Reclassification adjustments related to settlements of derivative contracts	(36,914)	1,982
Net change in derivative fair value	108,603	(80,219)
Foreign currency translation adjustment	<u>(7,224)</u>	<u>(8,643)</u>
Comprehensive loss	<u>\$(504,514)</u>	<u>\$ (45,746)</u>
Earnings (loss) per common share — basic	\$ (3.37)	\$ 0.26
Earnings (loss) per common share — diluted	\$ (3.37)	\$ 0.25
Basic weighted average shares outstanding	168,841	158,139
Diluted weighted average shares outstanding	168,841	169,060

The accompanying notes are an integral part of these condensed consolidated financial statements.

QUICKSILVER RESOURCES INC.
CONDENSED CONSOLIDATED BALANCE SHEETS
In thousands, except for share data — Unaudited

	<u>March 31,</u> <u>2009</u>	<u>December 31,</u> <u>2008</u>
ASSETS		
Current assets		
Cash and cash equivalents	\$ 430	\$ 2,848
Accounts receivable — net of allowance for doubtful accounts	109,694	143,315
Derivative assets at fair value	261,216	171,740
Other current assets	66,496	75,433
Total current assets	<u>437,836</u>	<u>393,336</u>
Investment in BreitBurn Energy Partners	139,402	150,503
Property, plant and equipment		
Oil and gas properties, full cost method (including unevaluated costs of \$577,391 and \$543,533, respectively)	2,357,275	3,142,608
Other property and equipment	670,032	655,107
Property, plant and equipment — net	<u>3,027,307</u>	<u>3,797,715</u>
Derivative assets at fair value	81,959	116,006
Deferred income taxes	108,779	—
Other assets	36,273	40,648
	<u>\$3,831,556</u>	<u>\$ 4,498,208</u>
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current portion of long-term debt	\$ 6,579	\$ 6,579
Accounts payable	193,954	282,636
Accrued liabilities	54,211	66,963
Derivative liabilities at fair value	852	9,928
Deferred income taxes	90,036	52,393
Total current liabilities	<u>345,632</u>	<u>418,499</u>
Long-term debt	2,687,214	2,586,046
Asset retirement obligations	39,276	34,753
Other liabilities	12,996	12,962
Deferred income taxes	35,052	234,385
Stockholders' equity		
Preferred stock, par value \$0.01, 10,000,000 shares authorized, none outstanding	—	—
Common stock, \$0.01 par value, 400,000,000 shares authorized; 173,947,192 and 171,742,699 shares issued, respectively	1,739	1,717
Paid in capital in excess of par value	662,256	656,958
Treasury stock of 4,673,730 and 4,572,795 shares, respectively	(36,064)	(35,441)
Accumulated other comprehensive income	249,569	185,104
Retained earnings (deficit)	<u>(192,491)</u>	<u>376,488</u>
Quicksilver stockholders' equity	685,009	1,184,826
Noncontrolling interests	26,377	26,737
Total equity	<u>711,386</u>	<u>1,211,563</u>
	<u>\$3,831,556</u>	<u>\$ 4,498,208</u>

The accompanying notes are an integral part of these condensed consolidated financial statements.

QUICKSILVER RESOURCES INC.
CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
In thousands — Unaudited

	Quicksilver Resources Inc. Stockholders						Total
	Common Stock	Additional Paid-in Capital	Treasury Stock	Accumulated Other Comprehensive Income	Retained Earnings (Deficit)	Noncontrolling Interest	
Balances at December 31, 2007	\$ 1,606	\$378,622	\$(12,304)	\$ 40,066	\$ 754,764	\$ 29,714	\$1,192,468
Net income	—	—	—	—	41,134	508	41,642
Hedge derivative contract settlements reclassified into earnings from accumulated other comprehensive income, net of income tax of \$1,027	—	—	—	1,982	—	—	1,982
Net change in derivative fair value, net of income tax benefit of \$39,686	—	—	—	(80,219)	—	—	(80,219)
Foreign currency translation adjustment	—	—	—	(8,643)	—	—	(8,643)
Issuance and vesting of stock compensation	5	3,740	(1,980)	—	—	264	2,029
Stock option exercises	1	857	—	—	—	—	858
Distributions paid on KGS common units	—	—	—	—	—	(1,972)	(1,972)
Balances at March 31, 2008	<u>\$ 1,612</u>	<u>\$383,219</u>	<u>\$(14,284)</u>	<u>\$ (46,814)</u>	<u>\$ 795,898</u>	<u>\$ 28,514</u>	<u>\$1,148,145</u>
Balances at December 31, 2008	\$ 1,717	\$656,958	\$(35,441)	\$ 185,104	\$ 376,488	\$ 26,737	\$1,211,563
Net income (loss)	—	—	—	—	(568,979)	1,670	(567,309)
Hedge derivative contract settlements reclassified into earnings from accumulated other comprehensive income, net of income tax benefit of \$16,950	—	—	—	(36,914)	—	—	(36,914)
Net change in derivative fair value, net of income tax of \$52,805	—	—	—	108,603	—	—	108,603
Foreign currency translation adjustment	—	—	—	(7,224)	—	—	(7,224)
Issuance and vesting of stock compensation	22	5,287	(623)	—	—	418	5,104
Stock option exercises	—	11	—	—	—	—	11
Distributions paid on KGS common units	—	—	—	—	—	(2,448)	(2,448)
Balances at March 31, 2009	<u>\$ 1,739</u>	<u>\$662,256</u>	<u>\$(36,064)</u>	<u>\$ 249,569</u>	<u>\$(192,491)</u>	<u>\$ 26,377</u>	<u>\$ 711,386</u>

The accompanying notes are an integral part of these condensed consolidated financial statements.

QUICKSILVER RESOURCES INC.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
In thousands — Unaudited

	For the Three Months Ended	
	March 31,	
	2009	2008
Operating activities:		
Net income (loss)	\$(567,309)	\$ 41,642
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion, depreciation and accretion	59,696	35,059
Impairment related to oil and gas properties	896,483	—
Deferred income tax expense (benefit)	(304,639)	22,455
Stock-based compensation	5,727	4,009
Non-cash interest expense	4,139	2,220
Non-cash loss from hedging and derivative activities	1,128	5,735
Income from BBEP in excess of cash distributions, net of impairment	11,101	—
Other	91	627
Changes in assets and liabilities		
Accounts receivable	33,536	(5,226)
Derivative assets at fair value	54,896	—
Other assets	1,566	(1,109)
Accounts payable	(21,436)	5,027
Income taxes payable	—	(45,144)
Accrued and other liabilities	(25,692)	(22,011)
Net cash provided by operating activities	149,287	43,284
Investing activities:		
Purchases of property, plant and equipment	(255,984)	(331,936)
Proceeds from sales of property, plant and equipment	416	—
Advances to BBEP	—	(50,150)
Return of investment from BBEP	—	3,440
Net cash used for investing activities	(255,568)	(378,646)
Financing activities:		
Issuance of debt	208,374	330,741
Repayment of debt	(101,188)	(18,061)
Debt issuance costs	(39)	—
Noncontrolling interest distributions	(2,448)	(1,972)
Proceeds from exercise of stock options	11	858
Purchase of treasury stock	(623)	(1,980)
Net cash provided by financing activities	104,087	309,586
Effect of exchange rate changes in cash	(224)	(474)
Net decrease in cash	(2,418)	(26,250)
Cash and cash equivalents at beginning of period	2,848	28,226
Cash and cash equivalents at end of period	\$ 430	\$ 1,976

The accompanying notes are an integral part of these condensed consolidated financial statements.

QUICKSILVER RESOURCES INC.
NOTES TO CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
UNAUDITED

1. ACCOUNTING POLICIES AND DISCLOSURES

The accompanying condensed consolidated interim financial statements of Quicksilver Resources Inc. have not been audited. In the opinion of our management, the accompanying condensed consolidated interim financial statements contain all adjustments necessary to present fairly our financial position as of March 31, 2009 and our results of operations and cash flows for the three months ended March 31, 2009 and 2008. All such adjustments are of a normal recurring nature. The results for interim periods are not necessarily indicative of annual results.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of certain assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during each reporting period. We believe our estimates and assumptions are reasonable, but actual results could differ from our estimates.

Certain disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been condensed or omitted. Accordingly, these financial statements should be read in conjunction with our consolidated financial statements and notes thereto included in our 2008 Annual Report on Form 10-K.

Earnings per Share

The following is a reconciliation of the weighted average common shares used in the basic and diluted earnings (loss) per common share calculations for the three-month periods ended March 31, 2009 and 2008. The basic and diluted earnings (loss) per common share for each of the periods presented have been computed in compliance with guidance provided in Financial Staff Position (“FSP”) EITF 03-6-1. For additional information see *Recently Issued Accounting Standards* below. For the quarter ended March 31, 2009, all potentially dilutive securities were excluded from the diluted net loss per share calculation as they were antidilutive. No potentially dilutive securities were excluded from the diluted net income per share calculation for the three-month period ended March 31, 2008.

	Three Months Ended	
	March 31,	
	2009	2008
	<small>(In thousands, except per share data)</small>	
Net income (loss)	\$ (568,979)	\$ 41,134
Impact of assumed conversions — interest on 1.875% convertible debentures, net of income taxes	—	475
Income (loss) available to stockholders assuming conversion of convertible debentures	<u>\$ (568,979)</u>	<u>\$ 41,609</u>
Weighted average common shares — basic	168,841	158,139
Effect of dilutive securities:		
Employee stock options	—	730
Employee stock unit awards	—	375
Contingently convertible debentures	—	9,816
Weighted average common shares — diluted	<u>168,841</u>	<u>169,060</u>
Earnings (loss) per common share — basic	\$ (3.37)	\$ 0.26
Earnings (loss) per common share — diluted	\$ (3.37)	\$ 0.25

Recently Issued Accounting Standards

• Pronouncements Impacting Quicksilver That Have Been Implemented

SFAS No. 141 (revised 2007), *Business Combinations*, (“SFAS No. 141(R)”) was issued in December 2007. SFAS No. 141(R) replaces SFAS No. 141, *Business Combinations*, while retaining its fundamental requirements that the acquisition method of accounting be used for all business combinations and for an acquirer to be identified for each business combination. SFAS No. 141(R) defines the acquirer as the entity that obtains control in the business combination and it establishes the criteria to determine the acquisition date. The Statement also requires an acquirer to recognize the assets acquired and liabilities assumed measured at their fair values as of the acquisition date. In addition, acquisition costs are required to be recognized separately from the acquisition. SFAS No. 141(R) was further clarified by FSP FAS 141(R)-1, issued on April 1, 2009. FSP FAS 141(R)-1 addressed application issues regarding initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. We will apply the Statement to any acquisition we enter into after January 1, 2009, but otherwise adoption had no effect on our financial statements.

SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements — an amendment of ARB No. 51* (“SFAS No. 160”) was issued in December 2007. The Statement amends prior standards to establish new accounting and reporting standards for the noncontrolling interest in a subsidiary (previously referred to as “minority interest”) and for the deconsolidation of a subsidiary. SFAS No. 160 clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as a component of its equity. The Statement also changes the way the consolidated income statement is presented by requiring consolidated net income to be reported at amounts that include the amounts attributable to both the parent and noncontrolling interest. Additionally, SFAS No. 160 establishes a single method for accounting for changes in a parent’s ownership interest in a subsidiary that do not result in deconsolidation. We adopted this Statement on January 1, 2009, which resulted in the reclassification of the minority interest liability of \$29.9 million and deferred tax benefit of \$3.2 million, or \$26.7 million to stockholders’ equity. Also, our adoption resulted in the reclassification of the \$79.3 million deferred gain related to the KGS IPO to “paid in capital in excess of par value” within stockholders’ equity. Our consolidated balance sheet as of December 31, 2008 has been presented to conform to SFAS No. 160.

In February 2008, the FASB issued FSP FAS 157-2, “*Effective Date of FASB Statement No. 157*” (“FSP FAS 157-2”), which granted a one-year deferral of the effective date of SFAS No. 157 as it applies to non-financial assets and liabilities that are recognized or disclosed at fair value on a nonrecurring basis (e.g. those measured at fair value in a business combination and asset retirement obligations). Beginning January 1, 2009, we applied SFAS No. 157 to non-financial assets and liabilities.

The FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities*, (“SFAS No. 161”) in March 2008. SFAS No. 161 requires disclosures of the fair value of all derivative and hedging instruments and their gains or losses in tabular format and information about credit risk-related features in derivative agreements, counterparty credit risk, and its strategies and objectives for using derivative instruments. We adopted SFAS No. 161 on January 1, 2009 and the prescribed disclosures may be found in Note 3.

In May 2008, the FASB issued FSP APB 14-1, “*Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement)*” (“FSP APB 14-1”), which clarifies that convertible debt instruments that may be settled in cash upon conversion (including partial cash settlement) are not addressed by paragraph 12 of APB Opinion No. 14, “*Accounting for Convertible Debt and Debt Issued with Stock Purchase Warrants.*” In addition, FSP APB 14-1 indicates that issuers of such instruments generally should separately account for the liability and equity components in a manner that will reflect the entity’s nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. We adopted FSP APB 14-1 on January 1, 2009, which resulted in recognition of a \$26.8 million addition to “paid in capital in excess of par value”, additional deferred tax liability of \$5.8 million and decreases to other assets, long-term debt and retained earnings of \$2.4 million, \$19.0 million and \$16.0 million, respectively. We have also presented all comparable prior period information in conformity with FSP APB 14-1.

	For the Three Months Ended March 31, 2008		
	As Originally Reported	As Adjusted	Effect of Change
	(In thousands, except for per share data)		
Operating income	\$ 70,723	\$ 70,723	\$ —
Income from earnings of BBEP	6,219	6,219	—
Interest expense and other	(10,346)	(11,949)	(1,603)
Income before income tax	66,596	64,993	(1,603)
Income tax (expense) benefit	(23,912)	(23,351)	561
Net income attributable to noncontrolling interests	(508)	(508)	—
Net income attributable to Quicksilver	<u>\$ 42,176</u>	<u>\$ 41,134</u>	<u>\$(1,042)</u>
Earnings per share — basic	\$ 0.27	\$ 0.26	\$ (0.01)
Earnings per share — diluted	\$ 0.25	\$ 0.25	\$ —

The FASB issued FSP EITF 03-6-1, “*Determining Whether Instruments Granted in Share-Based Payments Transactions Are Participating Securities*” (“FSP EITF 03-6-1”) in June 2008 and was effective and adopted by us on January 1, 2009. Under FSP EITF 03-6-1, unvested share-based payment awards that contain nonforfeitable rights to dividends (whether paid or unpaid) are participating securities and should be included in the computation of basic earnings per share pursuant to the two-class method. Based upon the characteristics of our equity awards, approximately 2.7 million restricted shares have been identified as participating securities and have been included in the basic earnings per share calculation for the three months ended March 31, 2009. Basic earnings per share for the quarter ended March 31, 2008 have been retrospectively adjusted to reflect approximately 1.1 million restricted shares as participating securities. Basic earnings per share for the quarter ended March 31, 2008 as re-presented were lowered by \$0.01 for the combined effect of additional participating securities pursuant to FSP EITF 03-6-1 and by lower net income pursuant to adopting FSP APB 14-1.

On April 9, 2009, the FASB issued FSP FAS 107-1 and APB 28-1, *Interim Disclosures about Fair Value of Financial Instruments*. This FSP amended SFAS No. 107, *Disclosures about Fair Value of Financial Instruments*, APB Opinion No. 28, *Interim Financial Reporting*, by requiring disclosures about fair value of financial instruments for interim reporting periods. The FSP also amended APB Opinion No. 28, *Interim Financial Reporting*, to require those disclosures in summarized financial information at interim reporting periods. We adopted the disclosures requirements under the FSP for the period ending March 31, 2009 as allowed by the FSP.

FSP FAS 115-52 and FAS 124.2, *Recognition and Presentation of Other-Than-Temporary Impairments*, was also issued on April 9, 2009. This FSP amends the other-than-temporary impairment guidance for debt securities held as investments and presentation and disclosure of other-than-temporary impairments for such securities. We adopted this FSP for the quarter ended March 31, 2009, but it did not impact us.

FSP FAS 157-4, *Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly*, (“FSP FAS 157-4”) was issued on April 9, 2009. FSP FAS 157-4 provides additional guidance for estimating fair value in instances when changes in the activity for a financial asset or liability have significantly decreased. We adopted FSP FAS 157-4 for the period ending March 31, 2009, which had no impact on fair value measurements at March 31, 2009.

• **Pronouncements Not Yet Implemented**

The SEC adopted revisions to its required oil and gas reporting disclosures in December 2008. The revisions impacting us include: 1) use of 12-month average of the first-day-of-the-month prices for determination of proved reserve values included in calculating full cost ceiling limitations; 2) limitations on the types of technologies that may be relied upon to establish the levels of certainty required to classify reserves; and 3) ability to disclose “probable” and “possible” reserves as defined by the SEC. The SEC also updated the required disclosure requirements and eliminated use of price recoveries subsequent to period end for use in the ceiling test. We will adopt these changes effective on January 1, 2010 in accordance with the SEC’s transition rules and are still reviewing the implications of this adoption.

2. ALLIANCE ACQUISITION

On August 8, 2008, Quicksilver completed the Alliance Acquisition, whereby the Company acquired leasehold, royalty and midstream assets associated with the Barnett Shale formation in northern Tarrant and southern Denton counties of Texas. The purchase price was funded as follows:

(In thousands)

Purchase Price:	
Cash paid	\$1,000,000
Cash received from post-closing settlement	(3,088)
Cash paid for acquisition-related expenses	1,368
Total cash	998,280
Issuance of 10,400,468 common shares	262,092
	<u>\$1,260,372</u>

The revised preliminary purchase price allocation is presented below:

(In thousands)

Allocation of Purchase Price:	
Oil and gas properties — proved	\$ 792,647
Oil and gas properties — unproved	446,371
Midstream assets	27,652
Liabilities assumed	(5,226)
Asset retirement obligations	(1,072)
	<u>\$1,260,372</u>

The revised preliminary purchase price allocation is based on preliminary estimates of oil and gas reserves and other valuations and estimates by our management and is subject to final closing adjustments and determination of the valuation of tangible assets related to wells, pipelines and facilities. We expect to finalize the purchase price allocation during the quarter ending September 30, 2009.

Pro Forma Information

The following table reflects the Company's unaudited consolidated pro forma statements of income as though the Alliance Acquisition, associated borrowings and issuance of Company common stock had taken place on January 1, 2008. The actual revenue and expenses for the acquisition are included in our 2008 consolidated results beginning on August 8, 2008. The following pro forma information is not necessarily indicative of the results of operations that would have been achieved if the acquisition had been effective on January 1, 2008. Pro forma results for the first quarter of 2008 are presented below:

(In thousands, except for per share data)

1st Quarter 2008 Pro Forma Results:	
Revenues	<u>\$182,662</u>
Net income	<u>\$ 33,111</u>
Earnings per share — basic	\$ 0.20
Earnings per share — diluted	\$ 0.19

3. DERIVATIVES AND FAIR VALUE MEASUREMENTS

We use derivatives to mitigate price risk associated with the sale of our natural gas, NGL and crude oil production. Prices for these products are capable of wide fluctuations that may negatively affect profitability and cash flow from operations. We mitigate the risk of adverse price movements through the use of swaps and collars, which also limits future gains from favorable price movements.

We enter into financial derivatives with counterparties who are generally lenders under our credit facility. The credit facility provides for collateralization of amounts outstanding from our derivative instruments in addition to amounts outstanding under the facility. Additionally, default on any of our obligations under derivative instruments with counterparty lenders could result in acceleration of the amounts outstanding under the credit facility. The credit facility and our internal credit policies require that any counterparties, including facility lenders, with whom we enter into commodity financial derivatives have credit ratings that meet or exceed BBB- or Baa3 from Standard and Poor's or Moody's, respectively.

The estimated fair values of our derivatives of March 31, 2009 and December 31, 2008 are provided below. Derivatives are recorded in the balance sheet as current and non-current derivative assets and liabilities as determined by the expected timing of settlements. As of March 31, 2009, we had price collars or fixed price swaps hedging our anticipated natural gas production of approximately 190 MMcfd for the remainder of 2009. We have also hedged approximately 120 MMcfd of our anticipated 2010 natural gas production using natural gas price collars. In March 2009, we executed the early settlement of a price collar that hedged the sale of 40 MMcfd of our forecasted 2010 natural gas production. We received \$54.9 million that had been previously recognized in AOCI. As natural gas is produced and sold during 2010, we will reclassify a portion of the settlement value from AOCI into natural gas revenue. Our gross derivative positions are presented as follows:

	Asset Derivatives		Liability Derivatives	
	<u>March 31, 2009</u>	<u>December 31, 2008</u>	<u>March 31, 2009</u>	<u>December 31, 2008</u>
	(in thousands)		(in thousands)	
Derivatives designated as hedging instruments under SFAS 133				
Commodity contracts reported in:				
Current derivative assets	\$261,994	\$ 179,079	\$ 778	\$ 2,500
Noncurrent derivative assets	81,959	116,006	—	—
Current derivative liabilities	—	—	852	1,865
Total derivatives designated as hedging instruments under SFAS 133	<u>\$343,953</u>	<u>\$ 295,085</u>	<u>\$ 1,630</u>	<u>\$ 4,365</u>
Derivatives not designated as hedging instruments under SFAS 133				
Michigan Sales Contract natural gas purchase derivatives ⁽¹⁾ reported in current derivative assets	\$ —	\$ —	\$ —	\$ 4,839
Michigan Sales Contract ⁽¹⁾ reported in current derivative liabilities	\$ —	—	—	8,063
Total derivatives not designated as hedging instruments under SFAS 133	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 12,902</u>
Total derivatives	<u>\$343,953</u>	<u>\$ 295,085</u>	<u>\$ 1,630</u>	<u>\$ 17,267</u>

⁽¹⁾ During 2009, our net cash payments were \$16.5 million, including derivative settlements, to satisfy our obligations under the Michigan Sales Contract.

The following table discloses the availability of prices and other inputs used in our estimation of fair value of all our derivative instruments at March 31, 2009:

	Fair Value Measurements as of March 31, 2009				Balance Sheet Total
	<u>Level 1</u>	<u>Level 2</u>	<u>Level 3</u> (in thousands)	<u>Other⁽¹⁾</u>	
Derivative assets	<u>\$ —</u>	<u>\$343,953</u>	<u>\$ —</u>	<u>\$ (778)</u>	<u>\$ 343,175</u>
Derivative liabilities	<u>\$ —</u>	<u>\$ 1,630</u>	<u>\$ —</u>	<u>\$ (778)</u>	<u>\$ 852</u>

	Fair Value Measurements as of December 31, 2008				Balance Sheet Total
	Level 1	Level 2	Level 3 (in thousands)	Other ⁽¹⁾	
Derivative assets	\$ —	\$295,085	\$ —	\$ (7,339)	\$ 287,746
Derivative liabilities	\$ —	\$ 17,267	\$ —	\$ (7,339)	\$ 9,928

⁽¹⁾ Represents amounts netted under master netting arrangements with counterparties.

The change in carrying value of our financial derivatives since December 31, 2008 principally resulted from the continued decline in market prices for natural gas relative to the prices in our derivative instruments partially offset by the \$54.9 million early settlement of a natural gas collar that hedged the sale of 2010 natural gas production, and by monthly settlements received during the three months ended March 31, 2009.

	Michigan Contract	Cash Flow Derivatives (in thousands)	Total
Derivative fair value at December 31, 2008	\$(12,901)	\$290,719	\$277,818
Net cash payment due	(3,518)	—	(3,518)
Net cash paid for monthly settlements	16,479	—	16,479
Net cash received from monthly settlements and reported in revenue	—	(53,864)	(53,864)
Ineffectiveness reported in other revenue	(60)	(1,068)	(1,128)
Cash received and reported in OCI	—	(54,896)	(54,896)
Change in value reported in OCI	—	161,432	161,432
Derivative fair value at March 31, 2009	\$ —	\$342,323	\$342,323

	Michigan Contract	Cash Flow Derivatives (in thousands)	Total
Derivative fair value at December 31, 2007	\$(63,777)	\$ (5,859)	\$ (69,636)
Net cash payment due	(7)	—	(7)
Net cash paid for monthly settlements	7,153	—	7,153
Net cash paid for monthly settlements and reported in revenue	—	3,009	3,009
Ineffectiveness reported in other revenue	337	(5,860)	(5,523)
Change in value reported in OCI	—	(119,646)	(119,646)
Derivative fair value at March 31, 2008	\$(56,294)	\$(128,356)	\$(184,650)

Gains and losses from the effective portion of derivative assets and liabilities held in AOCI that are expected to be reclassified to earnings over the next twelve months are \$181.7 million net of income taxes. Gains from the effective portion of non-current derivative assets will be reclassified to earnings from AOCI over the nine months ending December 31, 2010. Hedge derivative ineffectiveness resulted in losses of \$1.1 million and \$5.5 million recorded in other revenue for the three months ended March 31, 2009 and 2008, respectively.

4. INVESTMENT IN BREITBURN ENERGY PARTNERS L.P.

We own approximately 21.3 million common units of BBEP, a publicly traded limited partnership, which we acquired in connection with the BreitBurn Transaction. On June 17, 2008, BBEP announced that it had repurchased and retired 14.4 million units, which represented approximately 22% of the units previously outstanding. The resulting reduction in the number of BBEP common units outstanding increased our ownership from approximately 32% to approximately 41%.

During the first quarter of 2009, we evaluated our investment in BBEP for impairment in response to further decreases in prevailing commodity prices and BBEP's unit price since December 31, 2008. As a result of these decreases and the outlook for petroleum prices and broad limitations on available capital, we made the determination that the decline in value was other-than-temporary. Accordingly, our impairment analysis utilized the March 31, 2009 closing price of \$6.53 per BBEP unit, which resulted in an aggregate fair value of \$139.4 million for the portion of BBEP units owned by Quicksilver. The \$139.4 million aggregate fair value was compared to an aggregate carrying value of \$241.5 million. We recorded the difference of \$102.1 million as a pre-tax impairment charge during the first quarter of 2009. Additional impairment of our investment in BBEP units could occur during the remainder of 2009 as BBEP suspended distributions to unitholders citing its intention to repay debt and reduce its aggregate borrowings and letters of credit below 90% of its borrowing base.

We account for our investment in BBEP units using the equity method, utilizing a one-quarter lag from BBEP's publicly available information. Summarized estimated financial information for BBEP is as follows:

	For the Three Months Ended December 31, 2008	For the Two Months Ended December 31, 2007
	(In thousands)	
Revenues ⁽¹⁾	\$ 443,247	\$ 61,165
Operating expenses ⁽²⁾	165,796	44,365
Operating income	277,451	16,800
Interest and other ⁽³⁾	25,599	4,403
Income tax benefit	677	(669)
Minority interests	13	31
Net income	<u>\$ 251,162</u>	<u>\$ 13,035</u>
Net income available to common unitholders	<u>\$ 251,162</u>	<u>\$ 12,567</u>

(1) Includes \$346.3 million of unrealized gains and \$2.3 million of unrealized losses on commodity derivatives in the 2008 and 2007 periods, respectively.

(2) Includes \$86.4 million for impairment charges of its oil and gas properties in the 2008 period.

(3) Includes \$15.1 million for unrealized losses on interest rate swaps in the 2008 period.

	As of December 31, 2008
	(In thousands)
Current assets	\$ 140,566
Property, plant and equipment	1,840,341
Other assets	235,927
Current liabilities	79,990
Long-term debt	736,000
Other non-current liabilities	47,952
Partners' equity	1,352,892

For the three months ended March 31, 2009, we recognized income of \$102.1 million for our share of BBEP's income for the three months ended December 31, 2008. For the comparable 2008 period, we recognized income of \$6.2 million for the two months ended December 31, 2007.

Changes in the balance of our investment in BBEP for the first quarter of 2009 were as follows:

(In thousands)

Balance at December 31, 2008	\$ 150,503
Equity income in BBEP	102,084
Distributions from BBEP	(11,101)
Non-cash impairment of BBEP	(102,084)
Balance at March 31, 2009	<u>\$ 139,402</u>

5. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consisted of the following:

	March 31, 2009	December 31, 2008
	(In thousands)	
Oil and gas properties		
Subject to depletion	\$ 3,744,339	\$ 3,621,831
Unevaluated costs	577,391	543,533
Accumulated depletion	(1,964,455)	(1,022,756)
Net oil and gas properties	2,357,275	3,142,608
Other plant and equipment		
Pipelines and processing facilities	666,755	529,555
General properties	61,485	57,941
Construction in progress	16,440	134,557
Accumulated depreciation	(74,648)	(66,946)
Net other property and equipment	670,032	655,107
Property, plant and equipment, net of accumulated depletion and depreciation	<u>\$ 3,027,307</u>	<u>\$ 3,797,715</u>

Ceiling Test Analysis

Under the full cost method in accounting for our oil and gas properties, we must perform a quarterly ceiling test for each of our cost centers. In determining the ceiling limitation, the ceiling test incorporates pricing, costs and discount rates over which management has no influence. Additionally, we do not include the benefits associated with our ownership and consolidation of KGS.

The 2009 first quarter U.S. ceiling amount was computed using benchmark prices of \$3.63 per Mcf of natural gas, \$24.12 per barrel of NGL and \$49.66 per barrel of crude oil. When we determined the present value of our U.S. reserves, the carrying value of our U.S. oil and gas properties exceeded the ceiling limit by \$786.9 million (pre-tax). We computed the 2009 first quarter Canadian ceiling amount using a benchmark price of \$2.92 per Mcf. Upon calculation of the present value of our Canadian reserves, the carrying value of our Canadian oil and gas properties exceeded the ceiling limit by \$109.6 million (pre-tax). We recorded a total impairment charge of \$896.5 million in the first quarter of 2009 as summarized below:

	Net Capitalized Costs ⁽¹⁾	Ceiling Limitation ⁽²⁾	Pre-tax Charge for Impairment
	(In thousands)		
United States	\$2,727,130	\$1,940,263	\$786,867
Canada	458,135	348,519	109,616
Total	<u>\$3,185,265</u>	<u>\$2,288,782</u>	<u>\$896,483</u>

(1) Net capitalized costs before impairment includes all costs associated with development, exploration and acquisition of oil and gas properties net of accumulated depletion and impairment, reduced by the related deferred income tax liability and asset retirement obligations.

(2) The ceiling limitation is the sum of (i) estimated future net cash flows, discounted at 10% per annum, from proved reserves, based on unescalated period-end prices and costs, adjusted for asset retirement obligations and financial derivatives that hedge our oil and gas revenue, (ii) the costs of properties not being amortized, (iii) the lower of cost or market value of unproved properties not included in the costs being amortized, less (iv) income tax effects related to differences between book and tax bases of the oil and gas properties.

6. LONG-TERM DEBT

Long-term debt consisted of the following:

	<u>March 31,</u> <u>2009</u>	<u>December 31,</u> <u>2008</u>
	(In thousands)	
Senior secured credit facility	\$ 906,182	\$ 827,868
Senior secured second lien facility, net of unamortized discount	640,507	641,555
Senior notes due 2015, net of unamortized discount	469,288	469,062
Senior subordinated notes due 2016	350,000	350,000
Convertible debentures, net of unamortized discount	130,916	129,240
KGS credit agreement	196,900	174,900
Total debt	2,693,793	2,592,625
Less current maturities	(6,579)	(6,579)
Long-term debt	<u>\$2,687,214</u>	<u>\$ 2,586,046</u>

Senior Secured Credit Facility

Approximately \$283 million was available under the credit facility at March 31, 2009. In April 2009, the lenders affirmed our borrowing base at \$1.2 billion and the interest spreads on our facility were revised upward.

Convertible Debentures

The convertible debentures are contingently convertible into shares of Quicksilver common stock at a rate of 65.4418 shares for each \$1,000 debenture, subject to adjustment. Upon conversion, we have the option to deliver any combination of Quicksilver common stock and cash. Should all debentures be converted to Quicksilver common stock, an additional 9,816,270 shares would become outstanding; however, as of April 1, 2009, the debentures were not convertible.

On January 1, 2009, Quicksilver adopted FSP APB 14-1 as described in Note 1. The fair value of the equity component of our convertible debentures at the time of issuance was determined to be \$26.8 million, net of deferred tax liabilities based upon an interest rate of 6.75%. The remaining unamortized discount on the debentures at adoption was \$20.8 million and will be amortized through October 2011.

For the quarters ending March 31, 2009 and 2008, interest expense on our convertible debentures was recognized at an effective interest rate of 6.75% was \$2.4 million and \$2.3 million, respectively. Previously, interest expense for the quarter ended March 31, 2008 had been \$0.7 million for our convertible debentures. As of March 31, 2009, the carrying value of the \$150 million convertible debentures was \$130.9 million. The carrying value will be accreted to face value through October 2011.

KGS Credit Agreement

At March 31, 2009, KGS' borrowing capacity remained at the December 31, 2008 amount of \$235 million, with \$38.1 million of available capacity.

Summary of All Outstanding Debt

As of March 31, 2009, the Company was in compliance with all covenants associated with its long-term debt, other notes and loans. For a more complete description of our long-term debt, see Note 14, *Long-Term Debt*, to the consolidated financial statements in our 2008 Annual Report on Form 10-K.

The following table summarizes significant aspects of our long-term debt:

	<i>Priority of Right to Collateralized Assets ⁽⁷⁾</i>					<i>Recourse only to KGS assets</i>	
	Highest priority	<i>Equal priority</i>		<i>Equal priority</i>			Lowest priority
	Senior Secured Credit Facility	Senior Secured Second Lien Facility	Senior Notes	Senior Subordinated Notes	Convertible Debentures		KGS Credit Agreement
Maturity date	February 9, 2012	August 8, 2013	June 27, 2015	March 16, 2016	November 1, 2024	August 10, 2012	
Interest rate at March 31, 2009 ⁽¹⁾	2.81%	7.75%	8.25%	7.125%	1.875%	2.30%	
Base interest rate options ^{(5) (6)}	LIBOR, ABR or specified	LIBOR or ABR	N/A	N/A	N/A	LIBOR, ABR or specified	
Financial covenants for 2009 ⁽³⁾	- Minimum current ratio of 1.0 - Minimum EBITDA to interest expense ratio of 2.5 - Minimum reserve PV 10 plus 50% of BBEP investment fair value to total debt of 1.5 - Minimum reserve PV 10 plus 50% of BBEP investment fair value to secured debt of 2.0	- Minimum current ratio of 1.0 - Minimum EBITDA to interest expense ratio of 2.25 - Minimum reserve PV 10 plus 50% of BBEP investment fair value to total debt of 1.5 - Minimum reserve PV 10 plus 50% of BBEP investment fair value to secured debt of 2.0	N/A	N/A	N/A	- Maximum debt to EBITDA ratio of 4.5 - Minimum EBITDA to interest expense ratio of 2.5	
Financial covenants beyond 2009 ^{(3) (4)}	- Minimum current ratio of 1.0 - Minimum EBITDA to interest expense ratio of 2.5 - Minimum reserve PV 10 plus 50% of BBEP investment fair value to total debt of 1.5 Reserve PV 10 plus 50% of BBEP investment fair value to secured debt of 2.25 beginning December 31, 2010	- Minimum current ratio of 1.0 - Minimum EBITDA to interest expense ratio of 2.25 - Minimum reserve PV 10 plus 50% of BBEP investment fair value to total debt of 1.5 Reserve PV 10 plus 50% of BBEP investment fair value to secured debt steps to 2.25 beginning December 31, 2010	N/A	N/A	N/A	- Maximum debt to EBITDA ratio of 4.5 - Minimum EBITDA to interest expense ratio of 2.5	
Significant restrictive covenants ⁽³⁾	- Incurrence of debt - Incurrence of liens - Payment of dividends - Equity purchases - Asset sales - Affiliate transactions - Limitations on derivatives	- Incurrence of debt - Incurrence of liens - Payment of dividends - Equity purchases - Asset sales - Affiliate transactions - Limitations on derivatives	- Incurrence of debt - Incurrence of liens - Payment of dividends - Equity purchases - Asset sales - Affiliate transactions	- Incurrence of debt - Incurrence of liens - Payment of dividends - Equity purchases - Asset sales - Affiliate transactions	N/A	- Incurrence of debt - Incurrence of liens - Equity purchases - Asset sales - Limitations on derivatives	
Estimated fair value ⁽²⁾	\$906.2 million	\$525.0 million	\$313.5 million	\$166.3 million	\$108.4 million	\$196.9 million	

(1) Represents the weighted average borrowing rate payable to lenders

(2) The estimated fair value is determined based on market quotations on the balance sheet date for fixed rate obligations. We consider debt with market-based interest rates to have a fair value equal to its carrying value

(3) The covenant information presented in this table is qualified in all respects by reference to the full text of the covenants and related definitions contained in the documents governing the various components of our debt

(4) Represents the most restrictive requirement for each covenant during its period outstanding

(5) Interest rate options include a base rate plus a spread. For the Senior Secured Second Lien Facility the LIBOR rate has a floor of 3.25% and the ABR has a floor of 4.25%.

(6) The Senior Secured Credit Facility was amended to add a floor to ABR of one-month LIBOR plus 1%, increase the ABR margin to a range of 1.375% to 2.375% and increase the Eurodollar and specified rate margins to a range of 2.25% to 3.25% after the redetermination in April 2009

(7) Priority of right to assets is not necessarily the same as priority to receive payments

8. ASSET RETIREMENT OBLIGATIONS

The following table provides information about our estimated asset retirement obligations for the three-month period ended March 31, 2009.

(In thousands)

Beginning asset retirement obligations	\$ 35,193
Incremental liability incurred	4,448
Accretion expense	589
Change in estimates	157
Asset retirement costs incurred	(50)
Currency translation adjustment	(621)
Ending asset retirement obligations	39,716
Less current portion	(440)
Long-term asset retirement obligations	<u>\$ 39,276</u>

9. INCOME TAXES

Our unrecognized tax benefits remain at \$9.3 million at March 31, 2009 and we do not anticipate the total amount of unrecognized tax benefits will significantly increase or decrease within the next 12 months. We have not recognized any unrecognized tax benefits for state taxes.

During March 2009, we filed a federal income tax return for 2008 to claim a federal tax refund of \$41.1 million as a result of our taxable loss for the 2008 tax year. The refund was received in April 2009.

10. COMMITMENTS AND CONTINGENCIES

For a more complete description of our commitments and contingencies see Note 17, *Commitments and Contingencies*, to the consolidated financial statements in our 2008 Annual Report on Form 10-K.

Commitments

We had approximately \$9.6 million of surety bonds outstanding to fulfill contractual, legal or regulatory requirements. All surety bonds have an annual renewal option. In addition, we had commitments outstanding of approximately \$21.8 million to purchase components for our drilling program as of March 31, 2009.

11. STOCK-BASED COMPENSATION

For a more complete description of our stock-based compensation plans, see Note 20, *Stockholders' Equity*, to the consolidated financial statements in our 2008 Annual Report on Form 10-K.

Quicksilver Stock Options

Options to purchase shares of common stock were granted in 2009 with an estimated fair value of \$8.7 million. We recognized expense of \$1.2 million for stock options in the first three months of 2009. At March 31, 2009, we had unearned compensation cost of \$10.7 million remaining, which will be recognized in expense through January 2011.

We estimated the fair value of stock options granted in 2009 on the dates of grant using the Black-Scholes option pricing model with the following assumptions:

	Stock Options Issued
Wtd avg grant date fair value	\$6.21
Wtd avg grant date	Jan 2, 2009
Wtd avg risk-free interest rate	1.90%
Expected life (in years)	6.0
Wtd avg volatility	56.8%
Expected dividends	—

The following table summarizes stock option activity during the three months ended March 31, 2009:

	Shares	Wtd Avg Exercise Price	Wtd Avg Remaining Contractual Life (In years)	Aggregate Intrinsic Value (In thousands)
Outstanding at December 31, 2008	1,103,336	\$ 14.20		
Granted	2,605,699	6.21		
Exercised	(2,028)	5.51		
Cancelled	(31,879)	9.81		
Outstanding at March 31, 2009	<u>3,675,128</u>	<u>\$ 8.58</u>	<u>7.9</u>	<u>\$ 74</u>
Exercisable at March 31, 2009	<u>893,716</u>	<u>\$ 9.86</u>	<u>2.2</u>	<u>\$ 74</u>
Vested at March 31, 2009 or expected to vest in the future	<u>3,394,006</u>	<u>\$ 7.16</u>		

Cash received from the exercise of stock options was \$0.9 million for the three months ended March 31, 2008.

Quicksilver Restricted Stock and Restricted Stock Units

The following table summarizes information regarding our restricted stock and RSU activity:

	Payable in stock		Payable in cash	
	Shares	Wtd Avg Grant Date Fair Value	Stock Units	Wtd Avg Grant Date Fair Value
Outstanding at December 31, 2008	1,336,111	\$24.01	—	\$ —
Granted	2,264,679	6.23	339,835	6.22
Vested	(600,274)	23.31	—	—
Cancelled	(64,292)	12.51	—	—
Outstanding at March 31, 2009	<u>2,936,224</u>	<u>\$10.69</u>	<u>339,835</u>	<u>\$6.22</u>

At January 1, 2009, we had total unvested compensation cost of \$17.6 million. During the first three months of 2009, we recognized expense of \$4.1 million including adjustments for remeasuring the cash settled awards to their revised fair value. Grants of restricted stock and RSUs, which settle in stock or cash, during the three months ended March 31, 2009, had an estimated grant date fair value of \$16.2 million which will be recognized as expense over the vesting period. Unrecognized compensation cost remaining at March 31, 2009 for restricted stock and RSUs settled in stock was \$27.6 million, which will be

recognized through January 2011. The fair value of RSUs settled in cash was \$1.9 million at March 31, 2009. The total fair value of restricted shares and RSUs vested during the three months ended March 31, 2009 was \$3.7 million.

KGS Phantom Units

The following table summarizes information regarding KGS phantom unit activity:

	Payable in units		Payable in cash	
	Units	Wtd Avg Grant Date Fair Value	Units	Wtd Avg Grant Date Fair Value
Outstanding at December 31, 2008	139,918	\$25.15	60,319	\$21.63
Granted	405,428	10.06	—	—
Vested	(49,789)	25.25	—	—
Cancelled	(8,284)	17.03	(3,640)	21.36
Outstanding at March 31, 2009	<u>487,273</u>	<u>\$12.72</u>	<u>56,679</u>	<u>\$21.65</u>

At January 1, 2009, KGS had total unrecognized compensation cost of \$2.3 million related to unvested phantom unit awards. KGS recognized compensation expense of approximately \$0.6 million during the three months ended March 31, 2009, including \$0.1 million for remeasuring awards to be settled in cash to their revised fair value. KGS has unearned compensation expense of \$4.2 million at March 31, 2009 that will be recognized in expense through January 2011. Phantom units that vested during the three months ended March 31, 2009 had a fair value of \$1.3 million on their vesting date.

12. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The following subsidiaries of Quicksilver are guarantors of Quicksilver's Senior Notes due 2015 and Senior Subordinated Notes due 2016: Cowtown Pipeline Funding, Inc., Cowtown Pipeline Management, Inc., Cowtown Pipeline LP, and Cowtown Gas Processing, LP (collectively, the "Guarantor Subsidiaries"). Each of the Guarantor Subsidiaries is 100% owned by Quicksilver. The guarantees are full and unconditional and joint and several. The condensed consolidating financial statements below present the financial position, results of operations and cash flows of Quicksilver, the Guarantor Subsidiaries and non-guarantor subsidiaries of Quicksilver.

Condensed Consolidating Balance Sheets

	March 31, 2009				Quicksilver Resources Inc. Consolidated
	Quicksilver Resources Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (In thousands)	Eliminations	
ASSETS					
Current assets	\$ 530,105	\$ —	\$ 495,065	\$ (587,334)	\$ 437,836
Property and equipment	2,071,301	2,055	953,951	—	3,027,307
Investment in subsidiaries (equity method)	530,036	193,042	—	(583,676)	139,402
Other assets	<u>278,591</u>	<u>128,098</u>	<u>2,661</u>	<u>(182,339)</u>	<u>227,011</u>
Total assets	<u>\$ 3,410,033</u>	<u>\$ 323,195</u>	<u>\$ 1,451,677</u>	<u>\$(1,353,349)</u>	<u>\$ 3,831,556</u>
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	\$ 453,084	\$ 126,464	\$ 353,418	\$ (587,334)	\$ 345,632
Long-term liabilities	2,271,940	—	684,937	(182,339)	2,774,538
Stockholders' equity	685,009	196,731	386,945	(583,676)	685,009
Noncontrolling interests	—	—	26,377	—	26,377
Total liabilities and stockholders' equity	<u>\$ 3,410,033</u>	<u>\$ 323,195</u>	<u>\$ 1,451,677</u>	<u>\$(1,353,349)</u>	<u>\$ 3,831,556</u>

December 31, 2008

	<u>Quicksilver Resources Inc.</u>	<u>Guarantor Subsidiaries</u>	<u>Non-Guarantor Subsidiaries</u> (In thousands)	<u>Eliminations</u>	<u>Quicksilver Resources Inc. Consolidated</u>
ASSETS					
Current assets	\$ 502,803	\$ 163	\$ 426,297	\$ (535,927)	\$ 393,336
Property and equipment	2,756,915	1,774	1,039,026	—	3,797,715
Investment in subsidiaries (equity method)	596,149	170,150	—	(615,796)	150,503
Other assets	207,474	123,298	2,826	(176,944)	156,654
Total assets	<u>\$ 4,063,341</u>	<u>\$ 295,385</u>	<u>\$ 1,468,149</u>	<u>\$(1,328,667)</u>	<u>\$ 4,498,208</u>
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	\$ 518,837	\$ 122,677	\$ 312,912	\$ (535,927)	\$ 418,499
Long-term liabilities	2,359,678	—	685,412	(176,944)	2,868,146
Stockholders' equity	1,184,826	172,708	443,088	(615,796)	1,184,826
Noncontrolling interests	—	—	26,737	—	26,737
Total liabilities and stockholders' equity	<u>\$ 4,063,341</u>	<u>\$ 295,385</u>	<u>\$ 1,468,149</u>	<u>\$(1,328,667)</u>	<u>\$ 4,498,208</u>

Condensed Consolidating Statements of Income

For the Three Months Ended March 31, 2009

	<u>Quicksilver Resources Inc.</u>	<u>Guarantor Subsidiaries</u>	<u>Non-Guarantor Subsidiaries</u> (In thousands)	<u>Eliminations</u>	<u>Quicksilver Resources Inc. Consolidated</u>
Revenues	\$ 137,859	\$ 108	\$ 70,564	\$ (22,599)	\$ 185,932
Operating expenses	892,490	360	141,373	(22,599)	1,011,624
Equity in net earnings of subsidiaries	(54,897)	7,765	—	47,132	—
Operating income	(809,528)	7,513	(70,809)	47,132	(825,692)
Income from earnings of BBEP	—	—	—	—	—
Interest expense and other	(36,551)	1,383	(4,272)	—	(39,440)
Income tax benefit (provision)	277,100	(396)	21,119	—	297,823
Net income (loss)	\$ (568,979)	\$ 8,500	\$ (53,962)	\$ 47,132	\$ (567,309)
Net income attributable to noncontrolling interests	—	—	(1,670)	—	(1,670)
Net income(loss) attributable to Quicksilver	<u>\$ (568,979)</u>	<u>\$ 8,500</u>	<u>\$ (55,632)</u>	<u>\$ 47,132</u>	<u>\$ (568,979)</u>

For the Three Months Ended March 31, 2008

	<u>Quicksilver Resources Inc.</u>	<u>Guarantor Subsidiaries</u>	<u>Non-Guarantor Subsidiaries</u> (In thousands)	<u>Eliminations</u>	<u>Quicksilver Resources Inc. Consolidated</u>
Revenues	\$ 116,887	\$ —	\$ 53,375	\$ (12,645)	\$ 157,617
Operating expenses	66,957	499	32,083	(12,645)	86,894
Equity in net earnings of subsidiaries	11,895	2,376	—	(14,271)	—
Operating income	61,825	1,877	21,292	(14,271)	70,723
Income from earnings of BBEP	6,219	—	—	—	6,219
Interest expense and other	(7,049)	1,433	(6,333)	—	(11,949)
Income tax provision	(19,861)	(327)	(3,163)	—	(23,351)
Net income	\$ 41,134	\$ 2,983	\$ 11,796	\$ (14,271)	\$ 41,642
Net income attributable to noncontrolling interests	—	—	(508)	—	(508)
Net income attributable to Quicksilver	<u>\$ 41,134</u>	<u>\$ 2,983</u>	<u>\$ 11,288</u>	<u>\$ (14,271)</u>	<u>\$ 41,134</u>

Condensed Consolidating Statements of Cash Flows

	For the Three Months Ended March 31, 2009				
	<u>Quicksilver Resources Inc.</u>	<u>Guarantor Subsidiaries</u>	<u>Non-Guarantor Subsidiaries</u> (In thousands)	<u>Eliminations</u>	<u>Quicksilver Resources Inc. Consolidated</u>
Cash flow provided by operations	\$ 119,199	\$ 67	\$ 30,021	\$ —	\$ 149,287
Cash flow used for investing activities	(205,445)	9,985	(43,421)	(16,687)	(255,568)
Cash flow provided by financing activities	84,707	(10,052)	12,745	16,687	104,087
Effect of exchange rates on cash	(61)	—	(163)	—	(224)
Net decrease in cash and equivalents	(1,600)	—	(818)	—	(2,418)
Cash and equivalents at beginning of period	1,677	—	1,171	—	2,848
Cash and equivalents at end of period	<u>\$ 77</u>	<u>\$ —</u>	<u>\$ 353</u>	<u>\$ —</u>	<u>\$ 430</u>

	For the Three Months Ended March 31, 2008				
	<u>Quicksilver Resources Inc.</u>	<u>Guarantor Subsidiaries</u>	<u>Non-Guarantor Subsidiaries</u> (In thousands)	<u>Eliminations</u>	<u>Quicksilver Resources Inc. Consolidated</u>
Cash flow provided by operations	\$ (45,590)	\$ 9,093	\$ 79,781	\$ —	\$ 43,284
Cash flow used for investing activities	(231,747)	23,270	(132,502)	(37,667)	(378,646)
Cash flow provided by financing activities	252,122	(32,363)	52,160	37,667	309,586
Effect of exchange rates on cash	(58)	—	(416)	—	(474)
Net decrease in cash and equivalents	(25,273)	—	(977)	—	(26,250)
Cash and equivalents at beginning of period	27,010	—	1,216	—	28,226
Cash and equivalents at end of period	<u>\$ 1,737</u>	<u>\$ —</u>	<u>\$ 239</u>	<u>\$ —</u>	<u>\$ 1,976</u>

13. SUPPLEMENTAL CASH FLOW INFORMATION

Cash paid for interest and income taxes is as follows:

	Three Months Ended March 31,	
	<u>2009</u>	<u>2008</u>
	(In thousands)	
Interest	\$46,325	\$18,295
Income taxes	—	47,196

Other non-cash transactions include:

	Three Months Ended March 31,	
	<u>2009</u>	<u>2008</u>
	(In thousands)	
Working capital related to acquisition of property, plant and equipment	\$163,378	\$174,354

14. RELATED-PARTY TRANSACTIONS

As of March 31, 2009, members of the Darden family and entities controlled by them beneficially owned approximately 30% of the Company's outstanding common stock. Thomas F. Darden, Glenn Darden and Anne Darden Self are officers and directors of the Company.

Quicksilver and its associated entities paid \$0.2 million and \$0.6 million in the first quarter of 2009 and 2008, respectively, for rent on buildings owned by entities affiliated with Mercury. Rental rates have been determined based on comparable rates charged by third parties.

We paid \$0.1 million and \$0.2 million during the first quarter of 2009 and 2008, respectively, for use of an airplane owned by an entity controlled by members of the Darden family. Usage rates are determined based on comparable rates charged by third parties.

Quicksilver paid \$0.4 million during the first quarter of 2009 for delay rentals under leases for over 5,000 acres held by a related party entity. The lease terms were determined based on comparable prices and terms granted to third parties with respect to similar leases in the area.

Payments received from Mercury for sublease rentals, employee insurance coverage and administrative services during the first quarter of both 2009 and 2008 totaled \$0.1 million.

15. SEGMENT INFORMATION

We operate in two geographic segments, the United States and Canada, where we are engaged in the exploration and production segment of the oil and gas industry. Additionally, we operate in the midstream segment, where we provide natural gas processing and gathering services in the United States, predominantly through KGS. Revenue earned by KGS for the processing and gathering of Quicksilver gas are eliminated on a consolidated basis as are the costs of these services recognized by Quicksilver's producing properties. We evaluate performance based on operating income and property and equipment costs incurred.

	<u>Exploration & Production</u>		<u>Processing &</u>	<u>Corporate</u>	<u>Elimination</u>	<u>Quicksilver</u>
	<u>United States</u>	<u>Canada</u>	<u>Gathering</u>			<u>Consolidated</u>
	(in thousands)					
For the Three Months Ended						
March 31,						
2009						
Revenues	\$ 137,729	\$ 45,929	\$ 25,075	\$ —	\$(22,801)	\$ 185,932
Depletion, depreciation and accretion	44,250	10,293	4,827	326	—	59,696
Operating income	(739,359)	(82,076)	13,450	(17,707)	—	(825,692)
Property and equipment costs incurred	137,632	42,778	17,897	526	—	198,833
2008						
Revenues	\$ 116,731	\$ 38,626	\$ 15,185	\$ —	\$(12,925)	\$ 157,617
Depletion, depreciation and accretion	20,089	11,431	3,275	264	—	35,059
Operating income	62,951	16,830	4,805	(13,863)	—	70,723
Property and equipment costs incurred	212,006	76,443	54,430	381	—	343,260
Property, Plant and Equipment-						
net						
March 31, 2009	\$2,030,023	\$457,315	\$535,017	\$ 4,952		\$3,027,307
December 31, 2008	2,723,103	550,413	519,447	4,752	—	3,797,715

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

The following discussion and analysis of our consolidated financial condition and results of operations should be read in conjunction with our condensed consolidated financial statements, and notes thereto, and the other financial data included elsewhere in this quarterly report. The following discussion should also be read in conjunction with our audited consolidated financial statements, and notes thereto, and "Management's Discussion and Analysis of Financial Condition and Results of Operations" included in our 2008 Annual Report on Form 10-K.

EXECUTIVE OVERVIEW

We are an independent energy company engaged primarily in exploration, development and production of unconventional natural gas onshore in North America. We own producing oil and natural gas properties in the United States, principally in Texas, and in Alberta, Canada, where we had total estimated aggregate proved reserves of approximately 2.2 Tcfe of natural gas at December 31, 2008. We also have properties in the Horn River Basin of Northeast British Columbia and the Delaware Basin of West Texas where we are exploring for additional reserves, but have recognized no proved reserves. In addition, we own approximately 73% of KGS, a publicly traded midstream master limited partnership controlled by us, and we own approximately 41% of the limited partner units of BBEP, a publicly traded oil and natural gas exploration and production master limited partnership, which we account for using the equity method.

FIRST QUARTER AND OTHER 2009 HIGHLIGHTS

Increase in Production

Daily production increased 57% during the three months ended March 31, 2009 from the corresponding period in 2008. The production increase is discussed further in *Results of Operations* below.

Amended Senior Secured Credit Facility

On April 20, 2009, our bank group affirmed the borrowing base on our Senior Secured Credit Facility at \$1.2 billion. The borrowing base is subject to annual and certain other redeterminations. The credit facility continues to provide for \$1.2 billion of revolving credit commitments and we have the option to increase the facility to \$1.45 billion with consent of the lenders. We can also extend the facility, which matures on February 9, 2012, up to two additional years with lender approval.

In connection with affirming the borrowing base, Quicksilver and its bank group have amended the senior secured revolving credit facility to (i) increase the Eurodollar and specified rate margins from a range of 1.375% to 2.125% to a range of 2.25% to 3.25% (depending on the then-current borrowing base usage), (ii) increase the ABR margin from a range of 0% to 0.625% to a range of 1.375% to 2.375% (depending on the then-current borrowing base usage), (iii) add a floor to the ABR margin of one-month Libor plus 1%, and (iv) increase the unused commitment fee rate from a range of 0.25% to 0.375% to a flat rate of 0.5%. The margins across all grids will decrease by 0.25% upon full repayment of the Senior Secured Second Lien Facility.

Update on Horn River

During the first quarter of 2009, we spent \$29.3 million at our Horn River prospect where we have drilled a total of two wells. Our capital expenditures include costs related to infrastructure development, such as construction of roads. Also, we have reached an agreement with a third party that provides midstream services for the firm transportation of 3 MMcfd of natural gas out of the Horn River Basin with volumes increasing through May 2013 when the agreement allows transportation of up to 100 MMcfd. We expect that one of the wells drilled will commence production during the third quarter of 2009 with the second well commencing production during the fourth quarter of 2009.

BBEP Update

On April 17, 2009, BBEP announced that its borrowing base under its credit facility had been reaffirmed, with no additional fees and no increase in borrowing rates, to be \$760 million, which exceeded its then current borrowings of \$717 million. Additionally, BBEP suspended its distributions to remain in compliance with certain provisions of its credit facility and to redirect cash flow to reduce its debt. BBEP management stated that the future resumption of distributions may be at levels below the recent distribution rate, but it cannot forecast or predict when distributions will resume. We have previously received quarterly distributions of \$10 to \$11 million.

OUTLOOK FOR REMAINDER OF 2009

Commodity prices, drilling and well completion costs and access to capital are the most significant drivers of our business. As of the date of this quarterly report, the credit markets remain very tight and natural gas prices, both in the near-term and intermediate future, continue to experience downward pressure due to the global recession and the level of natural gas supply. As a result, we have reduced our 2009 capital program from \$600 million to approximately \$500 million, which we believe allows us to maintain flexibility and spend at or within our operating cash inflows for the year. We continue to focus primarily on the continued development of our properties in Texas and Alberta. For the remainder of 2009, we have allocated \$160 million for exploration and development activities, \$75 million for midstream facilities, including approximately \$28 million to be funded directly by KGS and \$5 million for other property and equipment. On a regional basis, approximately \$220 million has been allocated to Texas to drill approximately 75 wells on operated properties and to complete and tie-in approximately 50 of those wells.

Canada has been allocated \$25 million to maintain current production levels through drilling of approximately 10 wells, completing approximately 20 wells, tie-in of approximately 30 wells and to continue the previously discussed exploratory activities in the Horn River Basin. The remaining capital budget is spread among our other operating areas.

Our planned drilling program described above is dynamic and there are a number of factors that could impact our decisions to invest capital. Commodity prices, well costs, and program performance are a few factors that individually or in combination could change the scale or relative allocation of our capital program for 2009.

RESULTS OF OPERATIONS — Three Months Ended March 31, 2009 and 2008

Revenue

Natural Gas, NGL and Crude Oil

Production revenue:

	Natural Gas		NGL		Oil and Condensate		Total	
	2009	2008	2009	2008	2009	2008	2009	2008
	(In millions)							
Texas	\$ 72.7	\$ 58.6	\$ 25.4	\$ 48.4	\$ 3.3	\$ 6.5	\$ 101.4	\$ 113.5
Other U.S.	0.1	0.2	—	0.3	1.3	3.8	1.4	4.3
Hedging	34.8	2.6	—	(3.6)	—	(1.5)	34.8	(2.5)
Total U.S.	107.6	61.4	25.4	45.1	4.6	8.8	137.6	115.3
Canada	26.9	43.5	—	—	—	—	26.9	43.5
Hedging	19.0	(0.4)	—	—	—	—	19.0	(0.4)
Total Canada	45.9	43.1	—	—	—	—	45.9	43.1
Total Company	<u>\$ 153.5</u>	<u>\$ 104.5</u>	<u>\$ 25.4</u>	<u>\$ 45.1</u>	<u>\$ 4.6</u>	<u>\$ 8.8</u>	<u>\$ 183.5</u>	<u>\$ 158.4</u>

Average Daily Production Volumes:

	Natural Gas		NGL		Oil and Condensate		Equivalent Total	
	2009	2008	2009	2008	2009	2008	2009	2008
	(MMcfd)		(Bbld)		(Bbld)		(MMcfd)	
Texas	177.3	80.4	13,348	9,989	1,019	777	263.5	145.0
Other U.S.	0.3	0.5	—	41	475	474	3.1	3.6
Total U.S.	177.6	80.9	13,348	10,030	1,494	1,251	266.6	148.6
Canada	64.9	62.5	—	—	—	—	64.9	62.5
Total Company	<u>242.5</u>	<u>143.4</u>	<u>13,348</u>	<u>10,030</u>	<u>1,494</u>	<u>1,251</u>	<u>331.5</u>	<u>211.1</u>

Average Realized Prices:

	Natural Gas		NGL		Oil and Condensate		Equivalent Total	
	2009	2008	2009	2008	2009	2008	2009	2008
	(per Mcf)		(per Bbl)		(per Bbl)		(per Mcfe)	
Texas	\$4.56	\$ 8.01	\$21.13	\$53.28	\$36.24	\$ 91.58	\$4.28	\$ 8.60
Other U.S.	3.91	4.36	—	84.30	30.54	88.65	4.67	13.80
Hedging — U.S.	2.18	0.35	—	(4.05)	—	(13.01)	1.45	(0.19)
Total U.S.	6.73	8.34	21.13	49.36	34.42	77.46	5.74	8.53
Canada	4.60	7.64	—	—	—	—	4.60	7.64
Hedging — Canada	3.26	(0.07)	—	—	—	—	3.26	(0.07)
Total Canada	7.86	7.57	—	—	—	—	7.86	7.57
 Total Company	 \$7.04	 \$ 8.00	 \$21.13	 \$49.36	 \$34.42	 \$ 77.46	 \$6.15	 \$ 8.24

The following table summarizes the changes in our production revenues during the quarter ended March 31, 2009 compared with the first quarter of 2008:

	Natural Gas	NGL	Oil	Total
	(In thousands)			
Revenue for the quarter ended March 31, 2008	\$104,487	\$ 45,053	\$ 8,816	\$158,356
Volume changes	70,154	14,268	1,611	86,033
Price changes	(21,117)	(33,925)	(5,793)	(60,835)
Revenue for the quarter ended March 31, 2009	<u>\$153,524</u>	<u>\$ 25,396</u>	<u>\$ 4,634</u>	<u>\$183,554</u>

Natural gas revenue increased as a result of a 99.1 MMcfd increase in production partially offset by a decrease in realized prices for the first quarter of 2009 as compared to the comparable 2008 period. Natural gas volumes for Texas increased 96.9 MMcfd from the properties purchased in the Alliance Transaction and from new wells placed into service in our other Fort Worth Basin properties subsequent to March 31, 2008. These increases were partially offset by natural production declines from existing Fort Worth Basin wells. Canadian natural gas production increased slightly as production from new wells placed into service subsequent to March 31, 2008 were almost entirely offset by natural declines of production from existing wells.

The decrease in NGL revenue was due to a \$28.23 per barrel decrease in realized prices for the first quarter of 2009 compared to the 2008 period. Partially offsetting the price decrease was a 3,359 Bbld production increase from the Fort Worth Basin due to new wells placed into production subsequent to the first quarter of 2008 and the improved NGL recoveries from the Corvette Plan, which was placed into service by KGS during the first quarter of 2009.

Oil revenue for the first quarter of 2009 decreased due to a \$43.03 per barrel decrease in realized prices for the first quarter of 2009 as compared to the 2008 period. A 243 Bbld increase in production for the first quarter of 2009 partially offset the impact of lower realized prices. Higher oil production was due to new wells placed into production subsequent to the first quarter of 2008.

We expect our average production for the second quarter of 2009 to range from 330 MMcfd to 335 MMcfd.

Other Revenue

Other revenue in the quarter ended March 31, 2009 increased \$3.1 million from the comparable 2008 quarter. The increase was primarily due to a \$4.4 million reduction in losses resulting from partial ineffectiveness of the derivatives hedging our Canadian production for the first quarter of 2009 as compared to the 2008 first quarter, which was offset by slight decreases in revenue from marketing and transition services provided during the first quarter of 2008.

Operating Expenses

Oil and Gas Production Expense

	Three Months Ended March 31,			
	2009	2008		
	(In thousands, except per unit amounts)			
		Per Mcf		Per Mcf
Texas				
Cash expense	\$ 22,878	\$ 0.97	\$ 21,836	\$ 1.66
Equity compensation	303	0.01	314	0.02
	<u>\$ 23,181</u>	<u>\$ 0.98</u>	<u>\$ 22,150</u>	<u>\$ 1.68</u>
Other U.S.				
Cash expense	\$ 1,832	\$ 6.16	\$ 888	\$ 2.71
Equity compensation	50	0.17	48	0.15
	<u>\$ 1,882</u>	<u>\$ 6.33</u>	<u>\$ 936</u>	<u>\$ 2.86</u>
Total U.S.				
Cash expense	\$ 24,710	\$ 1.03	\$ 22,724	\$ 1.68
Equity compensation	353	0.01	362	0.03
	<u>\$ 25,063</u>	<u>\$ 1.04</u>	<u>\$ 23,086</u>	<u>\$ 1.71</u>
Canada				
Cash expense	\$ 7,075	\$ 1.21	\$ 8,763	\$ 1.54
Equity compensation	596	0.10	681	0.12
	<u>\$ 7,671</u>	<u>\$ 1.31</u>	<u>\$ 9,444</u>	<u>\$ 1.66</u>
Total Company				
Cash expense	\$ 31,785	\$ 1.07	\$ 31,487	\$ 1.64
Equity compensation	949	0.03	1,043	0.05
	<u>\$ 32,734</u>	<u>\$ 1.10</u>	<u>\$ 32,530</u>	<u>\$ 1.69</u>

Production expense was virtually unchanged primarily because of cost containment efforts in the Fort Worth Basin during the first quarter of 2009 when compared to the first quarter of 2008 despite higher production levels. As discussed above, our daily production from the Fort Worth Basin increased approximately 82% while production expense increased only \$1.0 million when comparing the first quarter of 2009 to the 2008 first quarter. Fort Worth Basin production expense per Mcfe for the first quarter of 2009 decreased 42% from the first quarter of 2008. First quarter Fort Worth Basin production expense of \$0.98 per Mcfe also reflected a 10% decrease from \$1.09 per Mcfe for the fourth quarter of 2008. These decreases resulted from ongoing stringent efforts to contain costs through vendor bidding processes, bulk purchasing and additional reliance on automation.

Canadian production expense for the first quarter of 2009 decreased \$1.8 million, or \$0.35 per Mcfe, from the first quarter of 2008. Decreased Canadian production expense was primarily the result of favorable changes in U.S.-Canadian exchange rates for the first quarter of 2009 when compared to the first quarter of 2008. Canadian production expense on a Canadian dollar basis increased approximately C\$0.7 million.

Production and Ad Valorem Taxes

	Three Months Ended March 31,			
	2009	2008		
	(In thousands, except per unit amounts)			
		Per Mcf		Per Mcf
Production and ad valorem taxes				
U.S.	\$ 3,942	\$ 0.16	\$ 1,738	\$ 0.13
Canada	<u>424</u>	0.07	<u>921</u>	0.16
Total production and ad valorem taxes	<u>\$ 4,366</u>	\$ 0.15	<u>\$ 2,659</u>	\$ 0.14

First quarter 2009 production and ad valorem taxes increased \$1.7 million when compared to the first quarter of 2008. The addition of wells and midstream facilities in the Fort Worth Basin over the past twelve months increased ad valorem taxes approximately \$2.3 million from the first quarter of 2008 to the first quarter of 2009.

Depletion, Depreciation and Accretion

	Three Months Ended March 31,			
	2009	2008		
	(In thousands, except per unit amounts)			
		Per Mcf		Per Mcf
Depletion				
U.S.	\$ 41,872	\$ 1.74	\$ 19,062	\$ 1.41
Canada	<u>9,102</u>	1.56	<u>10,505</u>	1.85
Total depletion	50,974	1.71	29,567	1.54
Depreciation of other fixed assets				
U.S.	\$ 7,310	\$ 0.30	\$ 4,422	\$ 0.33
Canada	<u>823</u>	0.14	<u>718</u>	0.13
Total depreciation	8,133	0.27	5,140	0.27
Accretion	<u>589</u>	0.02	<u>352</u>	0.01
Total depletion, depreciation and accretion	<u>\$ 59,696</u>	\$ 2.00	<u>\$ 35,059</u>	\$ 1.82

Higher depletion for the first quarter of 2009 was due primarily to an increase in both production and the depletion rate. Our U.S. depletion expense increased due primarily to a 79% increase in U.S. sales volumes. The lower depletion rate for our Canadian properties reflects favorable changes in the U.S.-Canadian dollar exchange rate and the maturity of our Canadian properties. The improvement in the exchange rate decreased depletion \$0.6 million when comparing the first quarter of 2009 to the 2008 first quarter. The \$2.9 million increase in U.S. depreciation for the first quarter of 2009 as compared to the 2008 first quarter was primarily associated with additions of Fort Worth Basin field compression and KGS' gathering system in addition to KGS' Corvette Plant that was placed into service in the first quarter of 2009. After recognition of the impairment charge (described more fully below), we expect our depletion expense on a Mcfe-basis to decrease 20% to 25% for the remainder of 2009.

Impairment of Oil and Gas Properties

We recognized a non-cash pre-tax charge of \$896.5 million (\$593.7 million after tax) for impairment related to both our U.S. and Canadian oil and gas properties in March 2009. Benchmark natural gas prices at March 31, 2009 for the U.S. and Canada decreased \$2.08 per Mcf and \$2.52 per Mcf, respectively, from December 31, 2008 and resulted in significant decreases to the future net cash flows from our proved oil and gas reserves. As required under full cost accounting rules, we performed a ceiling test by comparing the book value of our oil and gas properties, net of related deferred tax liability and asset retirement obligations, to the period-end ceiling limitation, which is the after-tax value of the future net cash flows from proved oil and gas reserves, including the effect of hedges. As also required under full cost accounting rules prescribed by the SEC, the ceiling amount was based upon period-end prices and costs held constant into the future, discounted at 10% per year. See Note 5 to our condensed consolidated financial statements for more information.

General and Administrative Expense

	Three Months Ended March 31,			
	2009		2008	
	(In thousands, except per unit amounts)			
		Per Mcf		Per Mcf
General and administrative expense				
Cash expense	\$ 12,665	\$ 0.42	\$ 12,296	\$ 0.64
Equity compensation	4,716	0.16	3,119	0.16
Total general and administrative expense	<u>\$ 17,381</u>	<u>\$ 0.58</u>	<u>\$ 15,415</u>	<u>\$ 0.80</u>

General and administrative expense for the first quarter of 2009 increased from the comparable 2008 period due a \$1.6 million increase for the vesting of stock-based compensation and \$0.8 million for all other employee compensation and benefits. Expenses for legal fees increased general and administrative expense by approximately \$1.4 million for the first quarter of 2009 as compared to the 2008 first quarter, and were associated with various corporate legal matters including our litigation with BBEP.

BBEP-Related Income and Expense

During the first quarter of 2009, we recognized \$102.1 million for equity earnings from our investment in BBEP for the fourth quarter of 2008 as compared to \$6.2 million for the two-month period ending December 31, 2007. A portion of the increase in equity earnings is the result of an increase in our proportionate ownership of BBEP from 32% to 41% as a result of BBEP's purchase and retirement of units in June 2008 while the remaining increase is primarily from large unrealized gains from its derivative instruments. BBEP continues to experience significant volatility in its net earnings due to changes in value of its derivative instruments for which it does not employ hedge accounting.

During the first quarter of 2009, we reevaluated our investment in BBEP for impairment in response to further decreases in prevailing commodity prices and BBEP's unit price since December 31, 2008. As a result of these decreases and the outlook for petroleum prices and broad limitations on available capital, we made the determination that the decline in value was other-than-temporary. Accordingly, our impairment analysis utilized the March 31, 2009 closing price of \$6.53 per BBEP unit, which resulted in an aggregate fair value of \$139.4 million for the portion of BBEP units owned by Quicksilver. The \$139.4 million aggregate fair value was compared to the \$241.5 million carrying value of our investment in BBEP. We recorded the difference of \$102.1 million as an impairment charge during the first quarter of 2009. We believe that additional impairment of our investment in BBEP units may occur during the remainder of 2009 as BBEP suspended distributions to unitholders citing its intention to repay debt and reduce its aggregate borrowings and letters of credit below 90% of its borrowing base. See Note 4 to our condensed consolidated financial statements for more information.

Interest Expense

	Three Months Ended March 31,	
	2009	2008
	(in thousands)	
Interest costs	\$ 37,373	\$ 12,934
Add: Non-cash interest	4,139	2,220
Less: Interest capitalized	(1,311)	(1,719)
Interest expense	<u>\$ 40,201</u>	<u>\$ 13,435</u>

Interest costs for the first quarter of 2009 were higher than the 2008 first quarter primarily because of the issuance of our 2015 Senior Notes and our Senior Secured Second Lien Facility in June and August of 2008, respectively, as well as additional borrowings outstanding under our Senior Secured Credit Facility. We expect interest expense to increase during future quarters based on increases to base borrowing rates, announced as part of the affirmation of our borrowing base under our Senior Secured Credit Facility, and by a decrease in the amount of interest costs capitalized after placing the Corvette Plant into service.

Income Tax Expense

	Three Months Ended March 31,	
	2009	2008
Income tax (benefit) — in thousands	\$(297,823)	\$23,351
Effective tax rate	34.4%	35.9%

Our provision for income taxes for the first quarter of 2009 decreased from the prior-year period due to a \$296.8 million decrease in U.S. income tax expense and a \$24.3 million decrease in Canadian income tax associated with lower pre-tax earnings that were primarily the result of impairment charges for our oil and gas properties recognized during the 2009 first quarter. The effective tax rate for the 2009 first quarter was most significantly affected by the resulting taxable net loss in both the U.S. and Canada that will be taxed at approximately 35% and approximately 25%, respectively. We expect our effective income tax rate to be in a range from 34% to 35% for all of 2009.

LIQUIDITY, CAPITAL RESOURCES AND FINANCIAL POSITION

Cash Flow Activity

Our financial condition and results of operations, including our liquidity and profitability, are significantly affected by the prices that we realize for our natural gas, NGL and oil production and the volumes of natural gas, NGL and oil that we produce.

The natural gas, NGL and oil that we produce are commodity products for which established trading markets exist. Accordingly, product pricing is determined by the relationship between supply and demand for these products in the relevant markets. Product supply is affected primarily by fluctuations in production volumes, and product demand is affected by the state of the economy in general, the availability and price of alternative fuels and a variety of other factors. Prices for our products historically have been volatile, and we have no meaningful influence over the timing and extent of price changes for our products. Although we have mitigated our near term exposure to such price declines through the use of derivative financial instruments covering substantial portions of our expected near-term production, we cannot confidently predict whether or when market prices for natural gas, NGL and oil will increase or decrease.

The volumes that we produce may be significantly affected by the rates at which we acquire leaseholds and other mineral interests and explore, exploit and develop our leaseholds and other mineral interests through drilling and production activities. These activities require substantial capital expenditures, and our ability to fund these activities through cash flow from our operations, borrowings and other sources may be significantly affected by both the continued turmoil in the credit and financial markets, resulting in us and other industry participants announcing reductions year-over-year in planned levels of capital expenditures and drilling activities for the remainder of 2009.

	Three Months Ended March 31,	
	2009	2008
	(In thousands)	
Net cash provided by operating activities	\$ 149,287	\$ 43,284
Net cash used for investing activities	(255,568)	(378,646)
Net cash provided by financing activities	104,087	309,586
Effect of exchange rate changes in cash	(224)	(474)

Operating Cash Flows

Net cash provided by operations in the first quarter of 2009 increased compared to the first quarter of 2008 primarily due to significantly higher production from our Texas oil and gas properties partially offset by lower average realized natural gas, NGL and crude oil prices. Additionally, the early settlement of a derivative hedging 40 MMcfd of 2010 natural gas production provided \$54.9 million of operating cash flow. Working capital otherwise decreased \$13.6 million in the first quarter of 2009. Furthermore, our 2009 first quarter receipt of cash distributions on our BBEP units increased \$1.4 million from the first quarter of 2008 to \$11.1 million. BBEP subsequently announced in April 2009 that it was suspending its distributions to its unitholders.

For the quarter ended March 31, 2009, price collars and swaps covered approximately 78% of our natural gas production and resulted in higher realized revenues from our production of \$53.9 million. As of March 31, 2009, we had price collars or fixed price swaps hedging our anticipated natural gas production of approximately 190 MMcfd for the remainder of 2009. We have also hedged approximately 120 MMcfd of our anticipated sale of 2010 natural gas production using natural gas price collars. We recorded the receipt of the \$54.9 million settlement of the previously discussed 40 Mmcfd contract in AOCI. As natural gas is produced and sold during 2010, we will reclassify the proportionate amount of the settlement into natural gas revenue.

In April 2009, we received a U.S. federal income tax refund of \$41.1 million attributable to the taxable loss generated during 2008 in the U.S. This amount was included in accounts receivable as of March 31, 2009.

Investing Cash Flows

Our expenditures for property and equipment (payments for property and equipment plus non-cash changes in working capital associated with property and equipment) during the first quarter of 2009 totaled \$198.8 million as detailed below.

	Three Months Ended March 31, 2009
	(In thousands)
Exploration and development:	
Texas	\$ 122,800
Other U.S.	14,563
Total U.S.	137,363
Canada	42,774
Total exploration and development	180,137
Midstream:	
Texas	16,906
Canada	991
Total midstream	17,897
Corporate and field office	799
Total plant and equipment costs incurred	<u>\$ 198,833</u>

During the first quarter of 2009, we paid \$256 million for property and equipment, a decrease of approximately \$76 million from the 2008 period.

Financing Cash Flows

As of March 31, 2009, approximately \$283 million was available for borrowing under our Senior Secured Credit Facility. We were in compliance with all covenants under our debt agreements at March 31, 2009. In April 2009, the lenders affirmed our borrowing base at \$1.2 billion and the spreads on our facility were revised upward. Please see *First Quarter and Other 2009 Highlights* on page 23 for additional information.

KGS' \$235 million senior secured credit facility had \$196.9 million of borrowings outstanding and KGS was in compliance with all of its covenants at March 31, 2009.

As of March 31, 2009 and December 31, 2008, we had the following total capitalization:

	March 31, 2009	December 31, 2008
	(In thousands)	
Long-term and short-term debt		
Senior secured credit facility	\$ 906,182	\$ 827,868
Senior secured second lien facility	640,507	641,555
Senior notes	469,288	469,062
Senior subordinated notes	350,000	350,000
Convertible subordinated debentures	130,916	129,240
KGS credit agreement	196,900	174,900
Total debt	<u>2,693,793</u>	<u>2,592,625</u>
Quicksilver's stockholders' equity	<u>685,009</u>	<u>1,184,826</u>
Total capitalization	<u>\$3,378,802</u>	<u>\$ 3,777,451</u>

We currently anticipate that remaining 2009 capital expenditures of approximately \$250 million will be funded from operating cash inflows.

Financial Position

The following impacted our balance sheet as of March 31, 2009, as compared to our balance sheet as of December 31, 2008:

- Our current derivative assets increased \$89.5 million while our deferred derivative assets decreased \$34.0 million as a result of higher derivative valuations partially offset by monthly settlements of \$53.9 million, and the early settlement of a derivative hedging a portion of our 2010 production for \$54.9 million. Our derivative liabilities decreased \$9.1 million as a result of the Michigan Sales Contract expiring on March 31, 2009. Our current

deferred income tax liability increased \$37.6 million as a result of an overall increase in the valuations of our derivatives.

- Our net property, plant and equipment balances decreased \$785 million as a result of charges for impairment of our oil gas properties of \$896.5 million and DD&A expense of \$59.7 million partially offset by \$198.8 million of costs incurred for property, plant and equipment.
- Our deferred income tax liability decreased \$104.1 million and a deferred tax asset of \$204.2 million was reclassified in connection with the impairment of both our investment in BBEP and our oil and gas properties.

Contractual Obligations and Commercial Commitments

There have been no significant changes to our contractual obligations and commercial commitments as disclosed in Item 7 in our 2008 Annual Report on Form 10-K.

Critical Accounting Estimates

Management's discussion and analysis of financial condition and results of operations are based on our condensed consolidated interim financial statements and related footnotes contained within this report. Our more critical accounting estimates used in the preparation of the consolidated financial statements were discussed in our 2008 Annual Report on Form 10-K. These critical estimates, for which no significant changes occurred during the three months ended March 31, 2009, include estimates and assumptions for:

- full cost ceiling calculation;
- oil and gas reserves;
- derivative instruments;
- asset retirement obligations;
- stock-based compensation; and
- income taxes.

The process of preparing financial statements in conformity with GAAP requires the use of estimates and assumptions to determine certain of the assets, liabilities, revenues and expenses. These estimates and assumptions are based upon what we believe is the best information available at the time of the estimates or assumptions. The estimates and assumptions could change materially as conditions within and beyond our control change. Accordingly, actual results could differ materially from those estimates.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements within the meaning of Item 303(a)(4) of SEC Regulation S-K.

Recently Issued Accounting Standards

The information regarding recent accounting pronouncements is included in Note 1 to our condensed consolidated financial statements included in Item 1 of this quarterly report.

ITEM 3. Quantitative and Qualitative Disclosures About Market Risk

We have established policies and procedures for managing risk within our organization, including internal controls. The level of risk assumed by us is based on our objectives and capacity to manage risk.

Our primary risk exposure is related to fluctuations in natural gas, oil and NGL commodity prices. We have mitigated the risk of adverse price movements through the use of swaps and collars; however, we have also limited future gains from favorable price movements.

Commodity Price Risk

We enter into financial derivative contracts to mitigate our exposure to commodity price risk associated with anticipated future natural gas, NGL and crude oil production. As of March 31, 2009, approximately 150 MMcfd and 40 MMcfd of natural gas price collars and swaps, respectively, have been put in place to hedge a portion of our anticipated production for the remainder of 2009. Also 120 MMcfd of 2010 natural gas production has been hedged using price collars. We believe we will have more predictability of our natural gas, NGL and crude oil revenues as a result of having these financial derivative contracts.

Utilization of our hedging program may result in natural gas, NGL and crude oil realized prices varying from market prices that we receive from the sale of natural gas, NGL and crude oil. Our revenue from natural gas, NGL and crude oil production was \$53.9 million higher and \$3.0 million lower as a result of our hedging programs for the first quarter of 2009 and 2008, respectively. Other revenue was \$1.1 million and \$5.5 million lower as a result of derivative and hedging ineffectiveness for the quarters ending March 31, 2009 and 2008, respectively.

The following table summarizes our open derivative positions as of March 31, 2009:

<u>Product</u>	<u>Type</u>	<u>Contract Period</u>	<u>Volume</u>	<u>Weighted Avg Price Per Mcf</u>	<u>Fair Value (In thousands)</u>
Gas	Swap	Apr 2009–Dec 2009	10 MMcfd	\$ 8.45	\$ 11,440
Gas	Swap	Apr 2009–Dec 2009	10 MMcfd	8.45	11,440
Gas	Swap	Apr 2009–Dec 2009	20 MMcfd	8.46	22,907
Gas	Collar	Apr 2009–Dec 2009	20 MMcfd	7.50– 9.34	17,913
Gas	Collar	Apr 2009–Dec 2009	20 MMcfd	7.75–10.20	19,256
Gas	Collar	Apr 2009–Dec 2009	10 MMcfd	7.75–10.26	9,655
Gas	Collar	Apr 2009–Dec 2009	20 MMcfd	8.25– 9.60	21,899
Gas	Collar	Apr 2009–Dec 2009	10 MMcfd	8.25–10.45	10,964
Gas	Collar	Apr 2009–Dec 2009	10 MMcfd	8.25–10.45	10,964
Gas	Collar	Apr 2009–Dec 2009	10 MMcfd	8.25–10.45	10,964
Gas	Collar	Apr 2009–Dec 2009	10 MMcfd	8.50–13.15	11,678
Gas	Collar	Apr 2009–Dec 2009	30 MMcfd	11.00–13.50	55,226
Gas	Collar	Apr 2009–Dec 2009	10 MMcfd	11.50–14.48	19,809
Gas	Collar	Jan 2010–Dec 2010	20 MMcfd	8.00–11.00	17,052
Gas	Collar	Jan 2010–Dec 2010	20 MMcfd	8.00–11.00	17,052
Gas	Collar	Jan 2010–Dec 2010	20 MMcfd	8.00–12.20	17,396
Gas	Collar	Jan 2010–Dec 2010	20 MMcfd	8.00–12.20	17,396
Gas	Collar	Jan 2010–Dec 2010	10 MMcfd	8.50–12.05	10,211
Gas	Collar	Jan 2010–Dec 2010	20 MMcfd	8.50–12.05	20,421
Gas	Collar	Jan 2010–Dec 2010	10 MMcfd	8.50–12.08	10,310
Gas	Basis	Apr 2009–Dec 2009	20 MMcfd	(1)	(852)
Gas	Basis	Apr 2009–Dec 2009	10 MMcfd	(1)	(426)
Gas	Basis	Apr 2009–Dec 2009	15 MMcfd	(1)	(166)
Gas	Basis	Apr 2009–Dec 2009	15 MMcfd	(1)	(186)
				Total	\$ 342,323

(1) Basis swaps for 60 MMcfd hedge the AECO basis adjustment at a weighted average deduction of \$0.84 per Mcf from NYMEX for the remainder of 2009.

In March 2009, we completed the early settlement of a natural gas collar that hedged 40 MMcfd through December 2010. Proceeds of approximately \$54.9 million were received and will be recognized in revenue and earnings as the associated hedged production volumes are sold.

In March 2009, we satisfied our obligation to deliver 25 MMcfd of natural gas under the Michigan Sales Contract. Our total 2009 net cash payments for the settlement were \$16.5 million.

The fair value of all derivative instruments included above was estimated using commodity prices quoted in active markets for the periods covered by the derivatives and the value confirmed by counterparties. Estimates were determined by applying the net differential between the prices in each derivative and market prices for future periods, as adjusted for estimated basis differential, to the volumes stipulated in each contract to arrive at an estimated future value. This estimated future value was discounted on each contract at rates commensurate with federal treasury instruments with similar contractual lives.

ITEM 4. Controls and Procedures

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report pursuant to Securities Exchange Act Rule 13a-15. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, as of March 31, 2009, our disclosure controls and procedures were effective to provide reasonable assurance that material information required to be disclosed by us (including our consolidated subsidiaries) in reports that we file or submit under the Securities Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting during the quarter ended March 31, 2009 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. Legal Proceedings

There has been no material change in legal proceedings from those described in Part I, Item 3. Legal Proceedings included in our 2008 Annual Report on Form 10-K.

ITEM 1A. Risk Factors

The following risk factors update the risk factors set forth in part I, Item IA, "Risk Factors" of our 2008 Annual Report on Form 10-K. You should carefully consider the following risk factors together with all of the other information included in this quarterly report and the other information that we file with the SEC, including the financial statements and related notes, when deciding to invest in us. You should be aware that the occurrence of any of the events described in this Risk Factors section and elsewhere in this quarterly report could have a material adverse effect on our business, financial position, results of operations and cash flows.

Natural gas, NGL and crude oil prices fluctuate widely, and low prices could have a material adverse impact on our business, financial condition, results of operations and cash flows.

Our revenue, profitability and future growth depend in part on prevailing natural gas, NGL and crude oil prices. These prices also affect the amount of cash flow available to service our debt, pay for our capital expenditures and fund our other liquidity needs, as well as our ability to borrow, raise additional capital and comply with the terms of our debt agreements. Among other things, the amount we can borrow under our Senior Secured Credit Facility is subject to periodic redetermination based in part on changing expectations of future prices. Lower prices may also reduce the amount of natural gas, NGLs and crude oil that we can economically produce.

While prices for natural gas and crude oil may be favorable at any point in time, they fluctuate widely, particularly as evidenced by price movements in the latter half of 2008 and the first quarter of 2009. Among the factors that can cause these fluctuations are:

- domestic and foreign demand for natural gas and crude oil;
- the level of domestic and foreign natural gas and crude oil supplies;
- the price and availability of alternative fuels;
- weather conditions;
- domestic and foreign governmental regulations;
- impact of trade organizations, such as OPEC;
- political conditions in oil and natural gas producing regions; and
- worldwide economic conditions.

Due to the volatility of natural gas and crude oil prices and our inability to control the factors that influence them, we cannot predict future pricing levels.

If natural gas, NGL or crude oil prices decrease, our exploration and development efforts are unsuccessful or our costs increase substantially, we may be required to recognize impairment of our oil and gas properties, which could have a material adverse effect on our financial condition, our results of operations and our ability to borrow under and comply with our debt agreements.

We employ the full cost method of accounting for our oil and gas properties, whereby all costs associated with acquiring, exploring for, and developing natural gas and crude oil reserves are capitalized and accumulated in separate country cost centers. These capitalized costs are amortized based on production from the reserves for each country cost center. Each capitalized cost pool cannot exceed the net present value of the underlying natural gas, NGL and crude oil reserves. Impairment to the carrying value of our oil and gas properties was recognized in both the fourth quarter of 2008 and the first quarter of 2009 and could occur again in the future if natural gas, NGL or crude oil prices at a reporting period end result in decreased value of our reserves. Increased operating and capitalized costs without incremental increases in natural gas and crude oil reserves could also trigger impairment based on decreased value of our reserves. In the event of impairment of our oil and gas properties, we reduce their carrying value and recognize expense in the amount of the impairment, which could be material and could adversely affect our financial condition and results of operations and our ability to borrow under and comply with the terms of our debt agreements.

Reserve estimates depend on many assumptions that may turn out to be inaccurate and any material inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities and present value of our reserves.

The process of estimating natural gas, NGL and crude oil reserves is complex. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves disclosed in our filings with the SEC.

In order to prepare these estimates, we and independent reserve engineers engaged by us must project production rates and timing of development expenditures. We and the engineers must also analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also requires economic assumptions with respect to natural gas and crude oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of natural gas, NGL and crude oil reserves are inherently imprecise.

Actual future production, natural gas, NGL and crude oil prices and revenue, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and crude oil reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves disclosed in this annual report. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing petroleum prices and other factors, which may be beyond our control.

At December 31, 2008, approximately 37% of our estimated proved reserves were undeveloped. Undeveloped reserves, by their nature, are less certain than comparable developed reserves. Recovery of undeveloped reserves requires additional capital expenditures and successful drilling and completion operations. Our reserve data assumes that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of our reserves and the costs associated with them in accordance with industry standards, there is risk that the estimated costs are inaccurate, that development will not occur as scheduled or that actual results will not be as estimated.

The present value of future net cash flows disclosed in Item 8 of our annual report on Form 10-K is not necessarily the fair value of our estimated proved natural gas and crude oil reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are based on prices and costs as of period end. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. Any changes in consumption by natural gas, NGL and crude oil purchasers or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of natural gas and crude oil properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor. The effective interest rate at various times and the risks associated with our business or the oil and natural gas industry in general will affect the appropriateness of the 10% discount factor in arriving at the reserves' actual fair value.

Our production is concentrated in a small number of geographic areas.

Approximately 75% of our 2008 production was from Texas and approximately 24% was from Alberta, Canada. Because of our concentration in these geographic areas, any regional events that increase costs, reduce availability of equipment or supplies, reduce demand or limit production, including weather and natural disasters, may impact us more than if our operations were more geographically diversified.

Our Canadian operations present unique risks and uncertainties, different from or in addition to those we face in our domestic operations.

In addition to the various risks associated with our U.S. operations, risks associated with our operations in Canada, where we have substantial operations, include, among other things, risks related to increases in taxes and governmental royalties, changes in laws and policies governing operations of foreign-based companies, currency restrictions and exchange rate fluctuations. Laws and policies of the United States affecting foreign trade and taxation may also adversely affect our Canadian operations.

We may have difficulty financing our planned growth.

We have experienced capital expenditure and working capital needs, particularly as a result of our property acquisition and drilling activities. For 2009, we plan to operate our capital program within our operating cash flows. However, in the future, we

may require additional financing above the level of cash generated by our operations to fund our growth. If revenue decreases as a result of lower petroleum prices or otherwise, our ability to expend the capital necessary to replace our reserves or to maintain production of current levels may be limited, resulting in a decrease in production over time. If our cash flow from operations is not sufficient to satisfy our capital expenditure requirements, we cannot be certain that additional financing will be available to us on acceptable terms or at all. In the event additional capital resources are unavailable, we may curtail our activities or be forced to sell some of our assets on an untimely or unfavorable basis.

We are vulnerable to operational hazards, transportation dependencies, regulatory risks and other uninsured risks associated with our activities.

The oil and natural gas business involves operating hazards such as well blowouts, explosions, uncontrollable flows of crude oil, natural gas or well fluids, fires, formations with abnormal pressures, treatment plant “downtime”, pipeline ruptures or spills, pollution, releases of toxic gas and other environmental hazards and risks, any of which could cause us to experience substantial losses. Also, the availability of a ready market for our natural gas and crude oil production depends on the proximity of reserves to, and the capacity of, natural gas and crude oil gathering systems, treatment plants, pipelines and trucking or terminal facilities.

U.S. and Canadian federal, state and provincial regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand and general economic conditions could adversely affect our ability to produce and market our natural gas, NGLs and crude oil. In addition, we may be liable for environmental damage caused by previous owners of properties purchased or leased by us.

As a result of operating hazards, regulatory risks and other uninsured risks, we could incur substantial liabilities to third parties or governmental entities. We maintain insurance against some, but not all, of such risks and losses in accordance with customary industry practice. Generally, environmental risks are not fully insurable. The occurrence of an event that is not covered, or not fully covered, by insurance could have a material adverse effect on our business, financial condition and results of operations.

The failure to replace our reserves could adversely affect our production and cash flows.

Our future success depends upon our ability to find, develop or acquire additional reserves that are economically recoverable. Our proved reserves will generally decline as reserves are produced, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves. In order to increase reserves and production, we must continue our development drilling and recompletion programs or undertake other replacement activities. Our current strategy is to maintain our focus on low-cost operations while increasing our reserve base and production through exploration and development of our existing properties. Our planned exploration or development projects or any acquisition activities that we may undertake might not result in meaningful additional reserves and we might not have continuing success drilling productive wells. Furthermore, while our revenue may increase if prevailing petroleum prices increase materially, our finding costs also could increase.

We have risk through our investment in BBEP.

We own a 41% limited partner interest in BBEP, but have no management oversight over BBEP, its financial condition, its operating results or its financial reporting process and are subject to the risks associated with BBEP’s business and operations. Moreover, the management of BBEP has discretion over the amount, if any, that they distribute to unitholders, and on April 17, 2009 BBEP announced that it was suspending such distributions.

The nature of our ownership interest in a publicly-traded entity subjects us to market risks associated with most ownership interests traded on a public exchange. Sales of substantial amounts of BBEP limited partner units, or a perception that such sales could occur, and various other factors, including BBEP suspending distributions on its units, could adversely affect the market price of BBEP limited partner units. Impairment to the carrying value of BBEP limited partnership units was recognized in both the fourth quarter of 2008 and the first quarter of 2009, and could occur again in the future if the market price for BBEP units declines further. In the event of impairment of our BBEP units, we reduce the carrying value of our BBEP units and recognize expense in the amount of the impairment, which could be material and could adversely affect our financial condition and results of operations and our ability to borrow under and comply with the provisions of our debt agreements.

We have risk through our ownership of KGS.

The following risk factors update the risk factors set forth in part I, Item IA, “Risk Factors” of our 2008 Annual Report on Form 10-K. You should carefully consider the following risk factors together with all of the other information included in this quarterly report and the other information that we file with the SEC, including the financial statements and related notes, when deciding to invest in us. You should be aware that the occurrence of any of the events described in this Risk Factors section and elsewhere in this quarterly report could have a material adverse effect on our business, financial position, results of operations and cash flows.

Natural gas, NGL and crude oil prices fluctuate widely, and low prices could have a material adverse impact on our business, financial condition, results of operations and cash flows.

Our revenue, profitability and future growth depend in part on prevailing natural gas, NGL and crude oil prices. These prices also affect the amount of cash flow available to service our debt, pay for our capital expenditures and fund our other liquidity needs, as well as our ability to borrow, raise additional capital and comply with the terms of our debt agreements. Among other things, the amount we can borrow under our Senior Secured Credit Facility is subject to periodic redetermination based in part on changing expectations of future prices. Lower prices may also reduce the amount of natural gas, NGLs and crude oil that we can economically produce.

While prices for natural gas and crude oil may be favorable at any point in time, they fluctuate widely, particularly as evidenced by price movements in the latter half of 2008 and the first quarter of 2009. Among the factors that can cause these fluctuations are:

- domestic and foreign demand for natural gas and crude oil;
- the level of domestic and foreign natural gas and crude oil supplies;
- the price and availability of alternative fuels;
- weather conditions;
- domestic and foreign governmental regulations;
- impact of trade organizations, such as OPEC;
- political conditions in oil and natural gas producing regions; and
- worldwide economic conditions.

Due to the volatility of natural gas and crude oil prices and our inability to control the factors that influence them, we cannot predict future pricing levels.

If natural gas, NGL or crude oil prices decrease, our exploration and development efforts are unsuccessful or our costs increase substantially, we may be required to recognize impairment of our oil and gas properties, which could have a material adverse effect on our financial condition, our results of operations and our ability to borrow under and comply with our debt agreements.

We employ the full cost method of accounting for our oil and gas properties, whereby all costs associated with acquiring, exploring for, and developing natural gas and crude oil reserves are capitalized and accumulated in separate country cost centers. These capitalized costs are amortized based on production from the reserves for each country cost center. Each capitalized cost pool cannot exceed the net present value of the underlying natural gas, NGL and crude oil reserves. Impairment to the carrying value of our oil and gas properties was recognized in both the fourth quarter of 2008 and the first quarter of 2009 and could occur again in the future if natural gas, NGL or crude oil prices at a reporting period end result in decreased value of our reserves. Increased operating and capitalized costs without incremental increases in natural gas and crude oil reserves could also trigger impairment based on decreased value of our reserves. In the event of impairment of our oil and gas properties, we reduce their carrying value and recognize expense in the amount of the impairment, which could be material and could adversely affect our financial condition and results of operations and our ability to borrow under and comply with the terms of our debt agreements.

Reserve estimates depend on many assumptions that may turn out to be inaccurate and any material inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities and present value of our reserves.

The process of estimating natural gas, NGL and crude oil reserves is complex. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves disclosed in our filings with the SEC.

In order to prepare these estimates, we and independent reserve engineers engaged by us must project production rates and timing of development expenditures. We and the engineers must also analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also requires economic assumptions with respect to natural gas and crude oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of natural gas, NGL and crude oil reserves are inherently imprecise.

Actual future production, natural gas, NGL and crude oil prices and revenue, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and crude oil reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves disclosed in this annual report. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing petroleum prices and other factors, which may be beyond our control.

At December 31, 2008, approximately 37% of our estimated proved reserves were undeveloped. Undeveloped reserves, by their nature, are less certain than comparable developed reserves. Recovery of undeveloped reserves requires additional capital expenditures and successful drilling and completion operations. Our reserve data assumes that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of our reserves and the costs associated with them in accordance with industry standards, there is risk that the estimated costs are inaccurate, that development will not occur as scheduled or that actual results will not be as estimated.

The present value of future net cash flows disclosed in Item 8 of our annual report on Form 10-K is not necessarily the fair value of our estimated proved natural gas and crude oil reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are based on prices and costs as of period end. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. Any changes in consumption by natural gas, NGL and crude oil purchasers or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of natural gas and crude oil properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor. The effective interest rate at various times and the risks associated with our business or the oil and natural gas industry in general will affect the appropriateness of the 10% discount factor in arriving at the reserves' actual fair value.

Our production is concentrated in a small number of geographic areas.

Approximately 75% of our 2008 production was from Texas and approximately 24% was from Alberta, Canada. Because of our concentration in these geographic areas, any regional events that increase costs, reduce availability of equipment or supplies, reduce demand or limit production, including weather and natural disasters, may impact us more than if our operations were more geographically diversified.

Our Canadian operations present unique risks and uncertainties, different from or in addition to those we face in our domestic operations.

In addition to the various risks associated with our U.S. operations, risks associated with our operations in Canada, where we have substantial operations, include, among other things, risks related to increases in taxes and governmental royalties, changes in laws and policies governing operations of foreign-based companies, currency restrictions and exchange rate fluctuations. Laws and policies of the United States affecting foreign trade and taxation may also adversely affect our Canadian operations.

We may have difficulty financing our planned growth.

We have experienced capital expenditure and working capital needs, particularly as a result of our property acquisition and drilling activities. For 2009, we plan to operate our capital program within our operating cash flows. However, in the future, we may require additional financing above the level of cash generated by our operations to fund our growth. If revenue decreases as a result of lower petroleum prices or otherwise, our ability to expend the capital necessary to replace our reserves or to maintain production of current levels may be limited, resulting in a decrease in production over time. If our cash flow from operations is not sufficient to satisfy our capital expenditure requirements, we cannot be certain that additional financing will be available to us on acceptable terms or at all. In the event additional capital resources are unavailable, we may curtail our activities or be forced to sell some of our assets on an untimely or unfavorable basis.

We are vulnerable to operational hazards, transportation dependencies, regulatory risks and other uninsured risks associated with our activities.

The oil and natural gas business involves operating hazards such as well blowouts, explosions, uncontrollable flows of crude oil, natural gas or well fluids, fires, formations with abnormal pressures, treatment plant “downtime”, pipeline ruptures or spills, pollution, releases of toxic gas and other environmental hazards and risks, any of which could cause us to experience substantial losses. Also, the availability of a ready market for our natural gas and crude oil production depends on the proximity of reserves to, and the capacity of, natural gas and crude oil gathering systems, treatment plants, pipelines and trucking or terminal facilities.

U.S. and Canadian federal, state and provincial regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand and general economic conditions could adversely affect our ability to produce and market our natural gas, NGLs and crude oil. In addition, we may be liable for environmental damage caused by previous owners of properties purchased or leased by us.

As a result of operating hazards, regulatory risks and other uninsured risks, we could incur substantial liabilities to third parties or governmental entities. We maintain insurance against some, but not all, of such risks and losses in accordance with customary industry practice. Generally, environmental risks are not fully insurable. The occurrence of an event that is not covered, or not fully covered, by insurance could have a material adverse effect on our business, financial condition and results of operations.

The failure to replace our reserves could adversely affect our production and cash flows.

Our future success depends upon our ability to find, develop or acquire additional reserves that are economically recoverable. Our proved reserves will generally decline as reserves are produced, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves. In order to increase reserves and production, we must continue our development drilling and recompletion programs or undertake other replacement activities. Our current strategy is to maintain our focus on low-cost operations while increasing our reserve base and production through exploration and development of our existing properties. Our planned exploration or development projects or any acquisition activities that we may undertake might not result in meaningful additional reserves and we might not have continuing success drilling productive wells. Furthermore, while our revenue may increase if prevailing petroleum prices increase materially, our finding costs also could increase.

We have risk through our investment in BBEP.

We own a 41% limited partner interest in BBEP, but have no management oversight over BBEP, its financial condition, its operating results or its financial reporting process and are subject to the risks associated with BBEP’s business and operations. Moreover, the management of BBEP has discretion over the amount, if any, that they distribute to unitholders, and on April 17, 2009 BBEP announced that it was suspending such distributions.

The nature of our ownership interest in a publicly-traded entity subjects us to market risks associated with most ownership interests traded on a public exchange. Sales of substantial amounts of BBEP limited partner units, or a perception that such sales could occur, and various other factors, including BBEP suspending distributions on its units, could adversely affect the market price of BBEP limited partner units. Impairment to the carrying value of BBEP limited partnership units was recognized in both the fourth quarter of 2008 and the first quarter of 2009, and could occur again in the future if the market price for BBEP units declines further. In the event of impairment of our BBEP units, we reduce the carrying value of our BBEP units and recognize expense in the amount of the impairment, which could be material and could adversely affect our financial condition and results of operations and our ability to borrow under and comply with the provisions of our debt agreements.

We have risk through our ownership of KGS.

Through our ownership interest in KGS, we share in KGS’ results of operations and may be entitled to distributions from KGS. Accordingly, we have diminished control over assets owned by KGS and assets which KGS has a right to acquire. We are also subject to the risks associated with KGS’ business and operations, including, but not limited to:

- changes in general economic conditions;
- fluctuations in natural gas prices;
- failure or delays in us and third parties achieving expected production from natural gas projects;
- competitive conditions in the midstream industry;

- actions taken on non-performance by third parties, including suppliers, contractors, operators, processors, transporters and customers;
- changes in the availability and cost of capital;
- operating hazards, natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- construction costs or capital expenditures exceeding estimated or budgeted amounts;
- the effects of existing and future laws and governmental regulations;
- the effects of future litigation; and
- other factors discussed in KGS' Annual Report on Form 10-K and as are or may be detailed from time to time in KGS' public announcements and other filings with the SEC.

We cannot control the operations of gas processing and transportation facilities we do not own or operate.

We deliver our Canadian production to market primarily by either the TransCanada or ATCO systems. We have no influence over the operation of these facilities and must depend upon their owners to minimize any loss of processing and transportation capacity.

The loss of key personnel could adversely affect our ability to operate.

Our operations are dependent on a relatively small group of key management personnel, including our executive officers. There is a risk that the services of all of these individuals may not be available to us in the future. Because competition for experienced personnel in our industry can be intense, we may be unable to find acceptable replacements with comparable skills and experience and their loss could have an adverse effect on us.

Competition in our industry is intense, and we are smaller and have a more limited operating history than many of our competitors.

We compete with major and independent oil and natural gas companies for property acquisitions. We also compete for the equipment and labor required to develop and operate our properties. Many of our competitors have substantially greater financial and other resources than we do. In addition, larger competitors may be able to absorb the burden of any changes in federal, state, provincial and local laws and regulations more easily than we can, which would adversely affect our competitive position. These competitors may be able to pay more for exploratory prospects and productive natural gas and crude oil properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than we can. Our ability to explore for natural gas and crude oil prospects and to acquire additional properties in the future will depend on our ability to conduct operations, to evaluate and select suitable properties and to complete transactions in this highly competitive environment. Furthermore, the oil and natural gas industry competes with other industries in supplying the energy and fuel needs of industrial, commercial, and other consumers.

Hedging our production may result in losses or limit our ability to benefit from price increases.

To reduce our exposure to petroleum price fluctuations, we have entered into financial hedging arrangements which may limit the benefit we would receive from increases in petroleum prices. These hedging arrangements also expose us to risk of financial losses in some circumstances, including the following:

- our production could be materially less than expected; or
- the other parties to the hedging contracts could fail to perform their contractual obligations.

The result of natural gas market prices exceeding collar ceilings requires us to make monthly cash payments. If we choose not to engage in hedging arrangements in the future, we could be more affected by changes in natural gas, NGL and crude oil prices than our competitors who engage in hedging arrangements.

Delays in obtaining oil field equipment and increases in drilling and other service costs could adversely affect our ability to pursue our drilling program and our results of operations.

As natural gas, NGL and crude oil prices increase, demand and costs for drilling equipment, crews and associated supplies, equipment and services can increase significantly. We cannot be certain that in a higher petroleum price environment we would be able to obtain necessary drilling equipment and supplies in a timely manner or on satisfactory terms, and we could experience shortages of, or material increases in the cost of, drilling equipment, crews and associated supplies, equipment and services. Any such delays and price increases could adversely affect our ability to pursue our drilling program and our results of operations.

Our activities are regulated by complex laws and regulations, including environmental regulations that can adversely affect the cost, manner or feasibility of doing business.

Natural gas, NGL and crude oil operations are subject to various U.S. and Canadian federal, state, provincial and local government laws and regulations that could change in response to economic or political conditions. Matters that are typically regulated include:

- discharge permits for drilling operations;
- water obtained for drilling purposes;
- drilling permits and bonds;
- reports concerning operations;
- spacing of wells;
- disposal wells;
- unitization and pooling of properties;
- environmental protection; and
- taxation.

From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of natural gas and crude oil wells below actual production capacity to conserve supplies of natural gas and crude oil. We also are subject to changing and extensive tax laws, the effects of which cannot be predicted.

The development, production, handling, storage, transportation and disposal of natural gas and crude oil, by-products and other substances and materials produced or used in connection with our operations are also subject to laws and regulations primarily relating to protection of human health and the environment. The discharge of natural gas, crude oil or pollutants into the air, soil or water may give rise to significant liabilities on our part to the government and third parties and may result in the assessment of civil or criminal penalties or require us to incur substantial costs of remediation.

Legal and tax requirements frequently are changed and subject to interpretation, and we are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations. We cannot assure you that existing laws or regulations, as currently interpreted or reinterpreted in the future, or future laws or regulations, will not materially adversely affect our business, results of operations and financial condition.

The risks associated with our debt could adversely affect our business, financial condition and results of operations and the value of our securities, and such risks could increase if we incur more debt.

Subject to the limits contained in our various debt agreements, we may incur additional debt. Our ability to incur additional debt and to comply with the terms of our debt agreements is affected by a variety of factors, including natural gas, NGL and crude oil prices and their effects on our financial condition, results of operations and cash flows. Among other things, our ability to borrow under our Senior Secured Credit Facility is subject to the quantity and value of our proved reserves and other assets, including our investment in BBEP. If we incur additional debt or fail to increase the quantity and value of our proved reserves, the risks that we now face as a result of our indebtedness could intensify.

We have demands on our cash resources in addition to interest expense, including operating expenses, principal payments under our debt and funding of our capital expenditures. Our level of debt, the value of our oil and gas properties and other assets, the demands on our cash resources and the provisions of our debt agreements could have important effects on our business and on the value of our securities. For example, they could:

- make it more difficult for us to satisfy our obligations with respect to our debt;
- require us to dedicate a substantial portion of our cash flow from operations to payments on our debt, thereby reducing the amount of our cash flow available for working capital, capital expenditures, acquisitions and other general corporate purposes;
- require us to make principal payments if the quantity and value of our proved reserves are insufficient to support our level of borrowings;
- limit our flexibility in planning for, or reacting to, changes in the oil and natural gas industry;
- place us at a competitive disadvantage compared to our competitors who may have lower debt service obligations and greater financing flexibility than we do;
- limit our financial flexibility, including our ability to borrow additional funds;

- increase our interest expense on our variable rate borrowings if interest rates increase;
- limit our ability to make capital expenditures to develop our properties;
- increase our vulnerability to exchange risk associated with Canadian dollar denominated indebtedness;
- increase our vulnerability to general adverse economic and industry conditions; and
- result in a default or event of default under our debt agreements, which, if not cured or waived, could adversely affect our financial condition, results of operations and cash flows.

Our ability to pay principal and interest on our long-term debt, to comply with the provisions of our debt agreements and to refinance our debt, may be affected by economic and capital markets conditions and other factors that may be beyond our control. If we are unable to service our debt and fund our other liquidity needs, we will be forced to adopt alternative strategies that may include:

- reducing or delaying capital expenditures;
- seeking additional debt financing or equity capital;
- selling assets;
- restructuring or refinancing debt; or
- reorganizing our capital structure.

We cannot assure you that we would be able to implement any of these strategies on satisfactory terms, if at all, and our inability to do so could cause the holders of our securities to experience a partial or total loss of their investment in us.

Our debt agreements restrict our ability to engage in certain activities.

Our debt agreements restrict our ability to, among other things:

- incur additional debt;
- pay dividends on or redeem or repurchase capital stock;
- make certain investments;
- incur or permit certain liens to exist;
- enter into certain types of transactions with affiliates;
- merge, consolidate or amalgamate with another company;
- transfer or otherwise dispose of assets, including capital stock of subsidiaries; and
- redeem subordinated debt.

Our debt agreements, among other things, also require the maintenance of financial covenants that are more fully described in Note 2 to the condensed consolidated financial statements in Item I of this quarterly report. Our ability to comply with these covenants and other provisions of our debt agreements may be affected by events beyond our control, and we may be unable to comply with all aspects of our debt agreements in the future. In addition, our ability to borrow under our Senior Secured Credit Facility is dependent upon the quantity and value of our proved reserves and other assets, including our investment in BBEP.

The provisions of our debt agreements may affect the manner in which we obtain future financing, pursue attractive business opportunities and plan for and react to changes in business conditions. In addition, failure to comply with the provisions of our debt agreements could result in an event of default which could enable the applicable creditors, subject to the terms and conditions of the applicable agreement, to declare the outstanding principal of that debt, together with accrued interest, to be immediately due and payable. Moreover, any of our debt agreements that contain a cross-default or cross-acceleration provision could also be subject to acceleration. If we were unable to repay the accelerated amounts, the creditors could proceed against the collateral granted to them to secure such debt. If the payment of our debt is accelerated, there can be no assurance that our assets would be sufficient to repay such debt in full, and the holders of our securities could experience a partial or total loss of their investment.

Parties with whom we do business may become unable or unwilling to timely perform their obligations to us.

We enter into contracts and transactions with various third parties, including contractors, suppliers, customers, lenders and counterparties to hedging arrangements, under which such third parties incur performance or payment obligations to us. Any delay or failure on the part of one or more of such third parties to perform their obligations to us could, depending upon the nature and magnitude of such failure or failures, have a material adverse effect on our business, financial condition and results of operations.

A small number of existing stockholders exercise significant control over our company, which could limit your ability to influence the outcome of stockholder votes.

Members of the Darden family, together with entities controlled by them, beneficially owned approximately 30% of our common stock as of March 31, 2009. As a result, they are generally able to significantly affect the outcome of stockholder votes, including votes concerning the election of directors, the adoption or amendment of provisions in our charter or bylaws and the approval of mergers and other significant corporate transactions.

A large number of our outstanding shares and shares to be issued upon conversion of our outstanding convertible debentures or exercise of our outstanding options may be sold into the market in the future, which could cause the market price of our common stock to drop significantly, even if our business is performing well.

Our shares that are eligible for future sale may adversely affect the price of our common stock. There were more than 169 million shares of our common stock outstanding at March 31, 2009. Approximately 117 million of these shares are freely tradable without substantial restriction or the requirement of future registration under the Securities Act. In addition, when the conditions permitting conversion of our convertible debentures are satisfied, the holders could elect to convert such debentures. Based on the applicable conversion rate at March 31, 2009, the holders' election to convert such debentures could result in an aggregate of 9,816,270 shares of our common stock being issued. We also had 3,675,128 options outstanding to purchase shares of our common stock at March 31, 2009.

Sales of substantial amounts of common stock, or a perception that such sales could occur, and the existence of conversion and option rights to acquire shares of common stock at prices that may be below the then current market price of the common stock, could adversely affect the market price of our common stock and could impair our ability to raise capital through the sale of our equity securities.

Our amended and restated certificate of incorporation, restated bylaws and stockholder rights plan contain provisions that could discourage an acquisition or change of control without our board of directors' approval.

Our amended and restated certificate of incorporation and restated bylaws contain provisions that could discourage an acquisition or change of control without our board of directors' approval. In this regard:

- our board of directors is authorized to issue preferred stock without stockholder approval;
- our board of directors is classified; and
- advance notice is required for director nominations by stockholders and actions to be taken at annual meetings at the request of stockholders.

In addition, we have adopted a stockholder rights plan which could also impede a merger, consolidation, takeover or other business combination involving us, even if that change of control might be beneficial to stockholders, thus increasing the likelihood that incumbent directors will retain their positions. In certain circumstances, the fact that corporate devices are in place that will inhibit or discourage takeover attempts could reduce the market value of our common stock.

- changes in general economic conditions;
- fluctuations in natural gas prices;
- failure or delays in us and third parties achieving expected production from natural gas projects;
- competitive conditions in the midstream industry;
- actions taken on non-performance by third parties, including suppliers, contractors, operators, processors, transporters and customers;
- changes in the availability and cost of capital;
- operating hazards, natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- construction costs or capital expenditures exceeding estimated or budgeted amounts;
- the effects of existing and future laws and governmental regulations;
- the effects of future litigation; and
- other factors discussed in KGS' Annual Report on Form 10-K and as are or may be detailed from time to time in KGS' public announcements and other filings with the SEC.

We cannot control the operations of gas processing and transportation facilities we do not own or operate.

We deliver our Canadian production to market primarily by either the TransCanada or ATCO systems. We have no influence over the operation of these facilities and must depend upon their owners to minimize any loss of processing and transportation capacity.

The loss of key personnel could adversely affect our ability to operate.

Our operations are dependent on a relatively small group of key management personnel, including our executive officers. There is a risk that the services of all of these individuals may not be available to us in the future. Because competition for experienced personnel in our industry can be intense, we may be unable to find acceptable replacements with comparable skills and experience and their loss could have an adverse effect on us.

Competition in our industry is intense, and we are smaller and have a more limited operating history than many of our competitors.

We compete with major and independent oil and natural gas companies for property acquisitions. We also compete for the equipment and labor required to develop and operate our properties. Many of our competitors have substantially greater financial and other resources than we do. In addition, larger competitors may be able to absorb the burden of any changes in federal, state, provincial and local laws and regulations more easily than we can, which would adversely affect our competitive position. These competitors may be able to pay more for exploratory prospects and productive natural gas and crude oil properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than we can. Our ability to explore for natural gas and crude oil prospects and to acquire additional properties in the future will depend on our ability to conduct operations, to evaluate and select suitable properties and to complete transactions in this highly competitive environment. Furthermore, the oil and natural gas industry competes with other industries in supplying the energy and fuel needs of industrial, commercial, and other consumers.

Hedging our production may result in losses or limit our ability to benefit from price increases.

To reduce our exposure to petroleum price fluctuations, we have entered into financial hedging arrangements which may limit the benefit we would receive from increases in petroleum prices. These hedging arrangements also expose us to risk of financial losses in some circumstances, including the following:

- our production could be materially less than expected; or
- the other parties to the hedging contracts could fail to perform their contractual obligations.

The result of natural gas market prices exceeding collar ceilings requires us to make monthly cash payments. If we choose not to engage in hedging arrangements in the future, we could be more affected by changes in natural gas, NGL and crude oil prices than our competitors who engage in hedging arrangements.

Delays in obtaining oil field equipment and increases in drilling and other service costs could adversely affect our ability to pursue our drilling program and our results of operations.

As natural gas, NGL and crude oil prices increase, demand and costs for drilling equipment, crews and associated supplies, equipment and services can increase significantly. We cannot be certain that in a higher petroleum price environment we would be able to obtain necessary drilling equipment and supplies in a timely manner or on satisfactory terms, and we could experience shortages of, or material increases in the cost of, drilling equipment, crews and associated supplies, equipment and services. Any such delays and price increases could adversely affect our ability to pursue our drilling program and our results of operations.

Our activities are regulated by complex laws and regulations, including environmental regulations that can adversely affect the cost, manner or feasibility of doing business.

Natural gas, NGL and crude oil operations are subject to various U.S. and Canadian federal, state, provincial and local government laws and regulations that could change in response to economic or political conditions. Matters that are typically regulated include:

- discharge permits for drilling operations;
- water obtained for drilling purposes;

- drilling permits and bonds;
- reports concerning operations;
- spacing of wells;
- disposal wells;
- unitization and pooling of properties;
- environmental protection; and
- taxation.

From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of natural gas and crude oil wells below actual production capacity to conserve supplies of natural gas and crude oil. We also are subject to changing and extensive tax laws, the effects of which cannot be predicted.

The development, production, handling, storage, transportation and disposal of natural gas and crude oil, by-products and other substances and materials produced or used in connection with our operations are also subject to laws and regulations primarily relating to protection of human health and the environment. The discharge of natural gas, crude oil or pollutants into the air, soil or water may give rise to significant liabilities on our part to the government and third parties and may result in the assessment of civil or criminal penalties or require us to incur substantial costs of remediation.

Legal and tax requirements frequently are changed and subject to interpretation, and we are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations. We cannot assure you that existing laws or regulations, as currently interpreted or reinterpreted in the future, or future laws or regulations, will not materially adversely affect our business, results of operations and financial condition.

The risks associated with our debt could adversely affect our business, financial condition and results of operations and the value of our securities, and such risks could increase if we incur more debt.

Subject to the limits contained in our various debt agreements, we may incur additional debt. Our ability to incur additional debt and to comply with the terms of our debt agreements is affected by a variety of factors, including natural gas, NGL and crude oil prices and their effects on our financial condition, results of operations and cash flows. Among other things, our ability to borrow under our Senior Secured Credit Facility is subject to the quantity and value of our proved reserves and other assets, including our investment in BBEP. If we incur additional debt or fail to increase the quantity and value of our proved reserves, the risks that we now face as a result of our indebtedness could intensify.

We have demands on our cash resources in addition to interest expense, including operating expenses, principal payments under our debt and funding of our capital expenditures. Our level of debt, the value of our oil and gas properties and other assets, the demands on our cash resources and the provisions of our debt agreements could have important effects on our business and on the value of our securities. For example, they could:

- make it more difficult for us to satisfy our obligations with respect to our debt;
- require us to dedicate a substantial portion of our cash flow from operations to payments on our debt, thereby reducing the amount of our cash flow available for working capital, capital expenditures, acquisitions and other general corporate purposes;
- require us to make principal payments if the quantity and value of our proved reserves are insufficient to support our level of borrowings;
- limit our flexibility in planning for, or reacting to, changes in the oil and natural gas industry;
- place us at a competitive disadvantage compared to our competitors who may have lower debt service obligations and greater financing flexibility than we do;
- limit our financial flexibility, including our ability to borrow additional funds;
- increase our interest expense on our variable rate borrowings if interest rates increase;
- limit our ability to make capital expenditures to develop our properties;
- increase our vulnerability to exchange risk associated with Canadian dollar denominated indebtedness;
- increase our vulnerability to general adverse economic and industry conditions; and
- result in a default or event of default under our debt agreements, which, if not cured or waived, could adversely affect our financial condition, results of operations and cash flows.

Our ability to pay principal and interest on our long-term debt, to comply with the provisions of our debt agreements and to refinance our debt, may be affected by economic and capital markets conditions and other factors that may be beyond our control.

If we are unable to service our debt and fund our other liquidity needs, we will be forced to adopt alternative strategies that may include:

- reducing or delaying capital expenditures;
- seeking additional debt financing or equity capital;
- selling assets;
- restructuring or refinancing debt; or
- reorganizing our capital structure.

We cannot assure you that we would be able to implement any of these strategies on satisfactory terms, if at all, and our inability to do so could cause the holders of our securities to experience a partial or total loss of their investment in us.

Our debt agreements restrict our ability to engage in certain activities.

Our debt agreements restrict our ability to, among other things:

- incur additional debt;
- pay dividends on or redeem or repurchase capital stock;
- make certain investments;
- incur or permit certain liens to exist;
- enter into certain types of transactions with affiliates;
- merge, consolidate or amalgamate with another company;
- transfer or otherwise dispose of assets, including capital stock of subsidiaries; and
- redeem subordinated debt.

Our debt agreements, among other things, also require the maintenance of financial covenants that are more fully described in Note 2 to the condensed consolidated financial statements in Item I of this quarterly report. Our ability to comply with these covenants and other provisions of our debt agreements may be affected by events beyond our control, and we may be unable to comply with all aspects of our debt agreements in the future. In addition, our ability to borrow under our Senior Secured Credit Facility is dependent upon the quantity and value of our proved reserves and other assets, including our investment in BBEP.

The provisions of our debt agreements may affect the manner in which we obtain future financing, pursue attractive business opportunities and plan for and react to changes in business conditions. In addition, failure to comply with the provisions of our debt agreements could result in an event of default which could enable the applicable creditors, subject to the terms and conditions of the applicable agreement, to declare the outstanding principal of that debt, together with accrued interest, to be immediately due and payable. Moreover, any of our debt agreements that contain a cross-default or cross-acceleration provision could also be subject to acceleration. If we were unable to repay the accelerated amounts, the creditors could proceed against the collateral granted to them to secure such debt. If the payment of our debt is accelerated, there can be no assurance that our assets would be sufficient to repay such debt in full, and the holders of our securities could experience a partial or total loss of their investment.

Parties with whom we do business may become unable or unwilling to timely perform their obligations to us.

We enter into contracts and transactions with various third parties, including contractors, suppliers, customers, lenders and counterparties to hedging arrangements, under which such third parties incur performance or payment obligations to us. Any delay or failure on the part of one or more of such third parties to perform their obligations to us could, depending upon the nature and magnitude of such failure or failures, have a material adverse effect on our business, financial condition and results of operations.

A small number of existing stockholders exercise significant control over our company, which could limit your ability to influence the outcome of stockholder votes.

Members of the Darden family, together with entities controlled by them, beneficially owned approximately 30% of our common stock as of March 31, 2009. As a result, they are generally able to significantly affect the outcome of stockholder votes, including votes concerning the election of directors, the adoption or amendment of provisions in our charter or bylaws and the approval of mergers and other significant corporate transactions.

A large number of our outstanding shares and shares to be issued upon conversion of our outstanding convertible debentures or exercise of our outstanding options may be sold into the market in the future, which could cause the market price of our common stock to drop significantly, even if our business is performing well.

Our shares that are eligible for future sale may adversely affect the price of our common stock. There were more than 169 million shares of our common stock outstanding at March 31, 2009. Approximately 117 million of these shares are freely tradable without substantial restriction or the requirement of future registration under the Securities Act. In addition, when the conditions permitting conversion of our convertible debentures are satisfied, the holders could elect to convert such debentures. Based on the applicable conversion rate at March 31, 2009, the holders' election to convert such debentures could result in an aggregate of 9,816,270 shares of our common stock being issued. We also had 3,675,128 options outstanding to purchase shares of our common stock at March 31, 2009.

Sales of substantial amounts of common stock, or a perception that such sales could occur, and the existence of conversion and option rights to acquire shares of common stock at prices that may be below the then current market price of the common stock, could adversely affect the market price of our common stock and could impair our ability to raise capital through the sale of our equity securities.

Our amended and restated certificate of incorporation, restated bylaws and stockholder rights plan contain provisions that could discourage an acquisition or change of control without our board of directors' approval.

Our amended and restated certificate of incorporation and restated bylaws contain provisions that could discourage an acquisition or change of control without our board of directors' approval. In this regard:

- our board of directors is authorized to issue preferred stock without stockholder approval;
- our board of directors is classified; and
- advance notice is required for director nominations by stockholders and actions to be taken at annual meetings at the request of stockholders.

In addition, we have adopted a stockholder rights plan which could also impede a merger, consolidation, takeover or other business combination involving us, even if that change of control might be beneficial to stockholders, thus increasing the likelihood that incumbent directors will retain their positions. In certain circumstances, the fact that corporate devices are in place that will inhibit or discourage takeover attempts could reduce the market value of our common stock.

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

Issuer Purchases of Equity Securities

The following table summarizes our repurchases of Quicksilver common stock during the quarter ended March 31, 2009.

Period	Total Number of Shares Purchased ⁽¹⁾	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plan ⁽²⁾	Maximum Number of Shares that May Yet Be Purchased Under the Plan ⁽²⁾
January 2009	98,304	\$6.15	—	—
February 2009	2,104	\$6.95	—	—
March 2009	527	\$5.96	—	—
Total	100,935	\$6.16	—	—

⁽¹⁾ Represents shares of common stock surrendered by employees to satisfy our income tax withholding obligations arising upon the vesting of restricted stock issued under our Amended and Restated 1999 Stock Option and Retention Stock Plan or Amended and Restated 2006 Equity Plan.

⁽²⁾ We do not currently have in place any publicly announced, specific plans or programs to purchase equity securities.

ITEM 3. Defaults Upon Senior Securities

None.

ITEM 4. Submission of Matters to a Vote of Security Holders

No items were submitted to a vote of stockholders during the first quarter ended March 31, 2009.

ITEM 5. Other Information

None.

ITEM 6. Exhibits:

<u>Exhibit No.</u>	<u>Description</u>
* 31.1	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
* 31.2	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
* 32.1	Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith

SIGNATURES

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

Dated: May 6, 2009

Quicksilver Resources Inc.

By: /s/ Glenn Darden
Glenn Darden
President and Chief Executive Officer

By: /s/ Philip Cook
Philip Cook
Senior Vice President — Chief Financial Officer

EXHIBIT INDEX

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* Filed herewith

CERTIFICATION

I, Glenn Darden, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Quicksilver Resources Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 6, 2009

/s/ Glenn Darden

Glenn Darden

President and Chief Executive Officer

CERTIFICATION

I, Philip Cook, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Quicksilver Resources Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 6, 2009

/s/ Philip Cook

Philip Cook

Senior Vice President — Chief Financial Officer

CERTIFICATION PURSUANT TO 18 U.S.C. § 1350, AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

Pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, in connection with the Quarterly Report on Form 10-Q of Quicksilver Resources Inc. (the "Company") for the quarter ended March 31, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, Philip Cook, Senior Vice President — Chief Financial Officer of the Company, and Glenn Darden, President and Chief Executive Officer of the Company, each certifies that, to his knowledge:

- (1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company as of the dates and for the periods expressed in the Report.

Date: May 6, 2009

By: /s/ Philip Cook
Philip Cook
Senior Vice President — Chief Financial Officer

By: /s/ Glenn Darden
Glenn Darden
President and Chief Executive Officer