ANNUAL 2009 REPORT

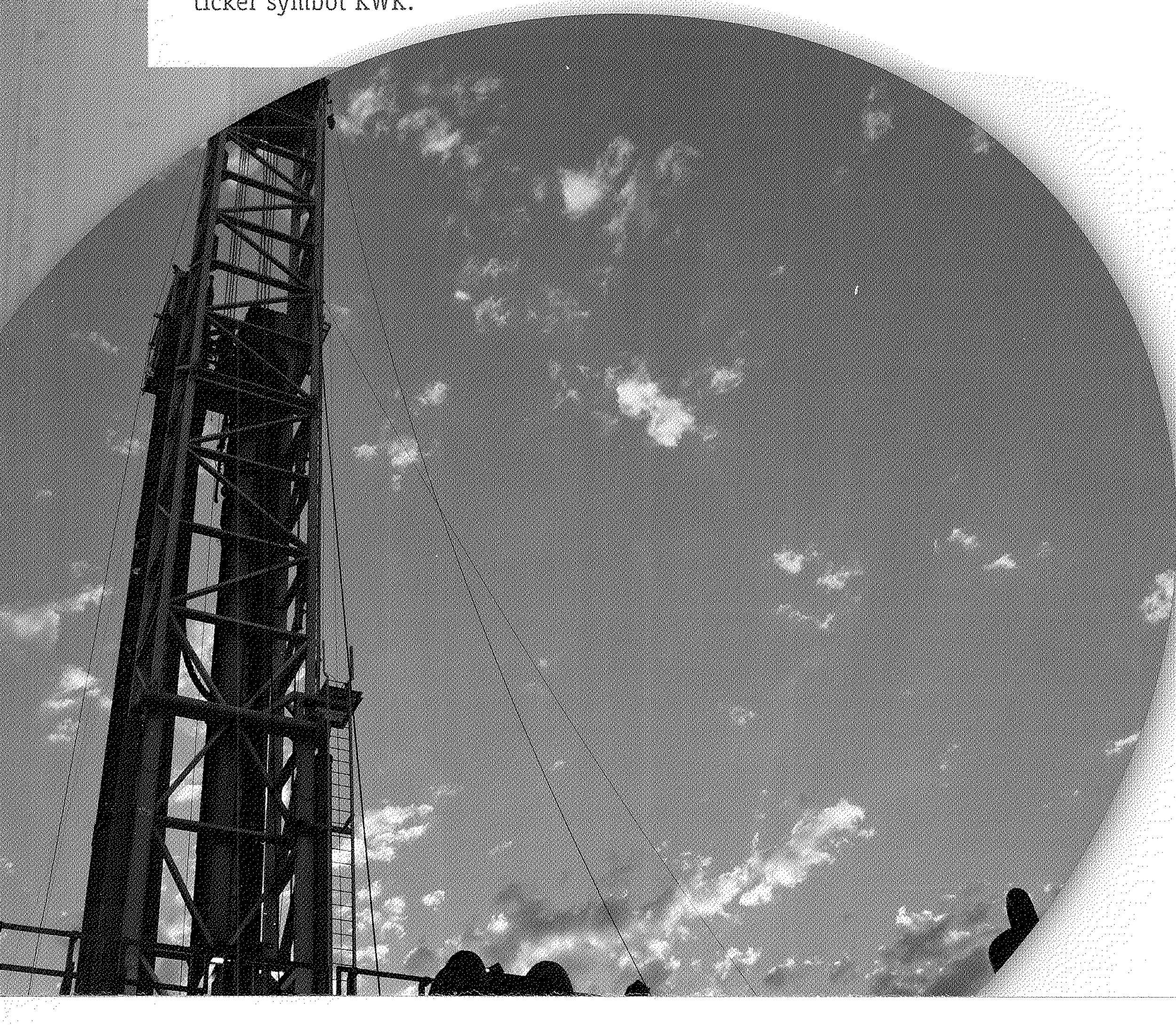
QUICKSILVER
RESOURCES

COMPANY PROFILE

Quicksilver Resources Inc. is an independent exploration and production company focused on identifying, acquiring and developing natural gas and oil located onshore in North America. Based in Fort Worth, Texas, the company is widely recognized as a leader in the development and production of unconventional reservoirs including shale gas and coalbed methane. The company's core developments are located in the shales of the Fort Worth Basin and the coals in the Canadian province of Alberta. In addition, the company is pursuing high-potential exploratory opportunities in the Horn River Basin of northeast British Columbia and selected basins in the U.S.

As of December 31, 2009, the company had estimated proved reserves of approximately 2.4 trillion cubic feet of natural gas equivalents, of which 99 percent were natural gas or natural gas liquids and 68 percent were proved developed. The company also owns approximately 61 percent of Quicksilver Gas Services LP, a midstream limited partnership and approximately 40 percent of BreitBurn Energy Partners L.P., an exploration and production limited partnership.

Quicksilver is a net asset value company which focuses on growth by the drill-bit through finding and developing long-life unconventional natural gas and oil reservoirs as a low-cost producer. The company's common shares are traded on the New York Stock Exchange under the ticker symbol KWK.



TO OUR SHAREHOLDERS

THE VALUE OF QUICKSILVER RESOURCES' GREAT ASSETS, low-cost structure, patience and teamwork was never more important than in 2009. Last year began with the economy in a deep, world-wide recession and conditions worsened through much of the year. For U.S. energy producers reduced demand for product resulted in some of the lowest natural gas prices in a decade. During these turbulent times, Quicksilver maintained its strategy to improve the company incrementally. Through perseverance by our entire team, we effectively executed on this strategy in 2009, which the market recognized by a 169% increase in our stock price. During the year, Quicksilver reached the following milestones:

- Achieved record production volumes of 325 MMcfed, up 23% from 2008
- Replaced 377% of production
- Reduced finding and development costs to $1.25/Mcfe compared to our 5-year average of $1.40/Mcfe
- Reduced unit cash production costs 24% to $1.04/Mcfe
- Increased reserves to 2.4 Tcfe, another company record
- Reduced net debt per proved developed reserve 33% to $0.92/Mcfe
- Produced initial gas from our Horn River Basin project thereby de-risking a new play

During the last several years the technological advancements in our industry, particularly in drilling and completions, have unlocked significant natural gas volumes from new shale gas basins. As a result, these added volumes have expanded the supply/demand imbalance and are depressing natural gas prices. What remains to be seen is just how economic each of these basins will be. At Quicksilver, we are fortunate that approximately 80% of production and 90% of reserves are derived from the Fort Worth Basin Barnett Shale, an area with more than 25 years of proven economic success.

The best protection we see for continued success is to be the lowest cost producer — one of our company's primary goals. In 2009, Quicksilver posted one of the lowest finding and development costs for proved developed reserves in the public company space. But perhaps even more meaningful is the full-cycle cost, which includes every cost a company spends to find, develop and produce the product. By this measure Quicksilver's cost was approximately $3.50/Mcfe in 2009. We view this very low cost structure as one of our most important competitive advantages and we continually fight this cost battle. To protect our margins we actively hedge the majority of our projected production volumes, which also underpins our capital program. For 2010, Quicksilver has used a combination of collars and swaps that cover approximately 67% of our expected production at a weighted-average floor price of approximately $7.00/Mcfe, and we are building on our hedge book for 2011 and 2012.

Couple cost containment with large discoveries of natural gas and you can begin to understand the attraction of this company. In 2009, Quicksilver began producing gas from what we believe is the company's highest-potential project to date, the Horn River Basin in northeast British Columbia, Canada. The company has secured exploratory licenses covering 130,000 contiguous net acres that contain a very thick section of Devonian shale at a depth of approximately 8,000 feet. In almost 20 years of producing shale gas, we have never seen this combination of gas content, permeability, and thickness of reservoir rock. We anticipate all of these factors will help us multiply production and reserves in the coming years. Quicksilver has modest drilling requirements to convert these exploratory licenses to leases giving us flexibility to develop this project for maximum return to our stockholders.

Quicksilver's 61% ownership, including 100% of the general partner interest, in Quicksilver Gas Services LP (KGS) and 40% ownership in BreitBurn Energy Partners L.P. (BBEP), both publicly-traded master limited partnerships, give the company added value and flexibility. In the case of KGS, Quicksilver derives significant benefits for its Barnett Shale assets by gathering and processing its gas through KGS' midstream assets. KGS expects to double its gathered volumes in 2010 as volumes from Quicksilver and third-party producers increase through the KGS systems. Quicksilver receives distributions from the unit ownership from both KGS and BBEP, which we expect will continue to provide another source of cash inflows for the company.

Looking ahead, Quicksilver is on solid footing on the financial and asset front. We are carefully monitoring expenditures and controlling costs to continue to grow production and reserves with further drilling in the Barnett Shale in Texas and the Horseshoe Canyon coals in Alberta, Canada. Our Horn River project is gaining steam and we anticipate moving to the development stage within the next couple of years. This timetable could accelerate with improved economic conditions. And as always, we are looking for new opportunities to enhance the value for our stockholders.

We would like to thank the 600 dedicated Quicksilver employees, whose hard work and talents drive this company forward. Of course, much credit is due to our board of directors whose guidance this past year was extraordinary. We would also like to thank the Quicksilver stockholders for their support. It is our job to continue to earn that support.

Very truly yours,

Glenn Darden
President and CEO

Thomas F. Darden
Chairman

FINANCIAL HIGHLIGHTS

In millions, except per share, production and product price data	2009 [a]	2008 [a]	2007 [a]	2006 [a]	2005 [a]
Total revenue	$ 832.7	$ 800.6	$ 561.3	$ 390.4	$ 310.4
Net income (loss) attributable to Quicksilver [b]	$ (557.5)	$ (378.3)	$ 475.4	$ 90.0	$ 84.0
Net income (loss) per diluted share [b]	$ (3.30)	$ (2.33)	$ 2.87	$ 0.58	$ 0.54
Diluted weighted average number of shares outstanding for the periods	169.0	162.0	168.0	166.3	164.9
Total assets	$ 3,612.9	$ 4,498.2	$ 2,773.8	$ 1,881.1	$ 1,241.4
Long-term debt	$ 2,427.5	$ 2,586.0	$ 788.5	$ 887.9	$ 469.3
Total equity	$ 696.8	$ 1,211.6	$ 1,192.5	$ 602.1	$ 406.4
Natural gas production (Mmcf)	86,040	68,128	59,619	53,266	46,769
Average realized natural gas price per Mcf [c]	$ 7.42	$ 8.10	$ 6.73	$ 6.05	$ 5.76
NGL production (Mmcfe)	29,860	25,176	14,826	4,476	1,338
Average realized NGL price per Mcfe [c]	$ 4.55	$ 7.57	$ 7.21	$ 6.48	$ 6.51
Crude oil production (Mbbl)	425	483	584	587	553
Average realized price per Bbl [c]	$ 51.85	$ 78.83	$ 63.87	$ 59.99	$ 50.50

(a) Share and per share amounts have been adjusted to reflect a three-for-two stock split during June 2005 and a two-for-one stock split during January 2008.

(b) Net loss attributable to Quicksilver and net loss per diluted share for 2009 include approximately $722 million and $4.27 per diluted share, respectively, associated with impairment charges on U.S. and Canadian oil and gas properties and investment in BreitBurn Energy Partners LP. Net loss attributable to Quicksilver and net loss per diluted share for 2008 include approximately $620 million and $3.84 per diluted share, respectively, associated with impairment charges on U.S. oil and gas properties and investment in BreitBurn Energy Partners LP. Net income attributable to Quicksilver and net income per diluted share for 2007 include $363.3 million and $2.16 per diluted share, respectively, associated with the gain on sale of all of our Northeast Operations net of divestiture-related expenses and costs and the loss on related natural gas sales contracts.

(c) Average realized prices reflect the effect of hedging transactions.

The statements in this Annual Report regarding future events, occurrences, circumstances, activities, performance, outcomes and results are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Although these statements reflect the current views, assumptions and expectations of Quicksilver Resources' management, the matters addressed herein are subject to numerous risks and uncertainties, which could cause actual activities, performance, outcomes and results to differ materially from those indicated. Factors that could result in such differences or otherwise materially affect Quicksilver Resources' financial condition, results of operations and cash flows include: changes in general economic conditions; fluctuations in natural gas, NGL and oil prices; failure or delays in achieving expected production from exploration and development projects; uncertainties inherent in estimates of natural gas, NGL and oil reserves and predicting natural gas, NGL and oil reservoir performance; effects of hedging natural gas, NGL and 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, including environmental and climate change requirements; the effects of existing or future litigation; and other factors disclosed in Quicksilver Resources' filings with the Securities and Exchange Commission. The forward-looking statements included in this Annual Report are made only as of the date of this Annual Report, and we undertake no obligation to update any of these forward-looking statements to reflect subsequent events or circumstances except to the extent required by applicable law.

Please refer to the calculations of Finding & Development Costs, Production Replacement Ratio and Net Debt that follow the signature page of the Form 10-K.

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

FORM 10-K

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

For the fiscal year ended December 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	**75-2756163**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
777 West Rosedale St., Fort Worth, Texas	**76104**
(Address of principal executive offices)	(Zip Code)

817-665-5000
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, $0.01 par value per share	New York Stock Exchange
Preferred Share Purchase Rights, $0.01 par value per share	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ☐ No ☑

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 the past 90 days.
Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

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.
Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ 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 ☑

As of June 30, 2009, the aggregate market value of the registrant's common stock held by non-affiliates of the registrant was $1,087,255,512 based on the closing sale price of $9.29 as reported on the New York Stock Exchange.

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

Class	Outstanding at February 15, 2010
Common Stock, $0.01 par value per share	170,222,678 shares

DOCUMENTS INCORPORATED BY REFERENCE

Document	Parts Into Which Incorporated
Proxy Statement for the Registrant's May 19, 2010 Annual Meeting of Stockholders	Part III

Pages 112 to 156 of our 2009 Form 10-K, incorporating the financial statements of BreitBurn Energy Partners L.P., have been intentionally omitted from this Annual Report.

DEFINITIONS

As used in this Annual Report unless the context otherwise requires:

"**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
"**Canada**" means the division of Quicksilver encompassing oil and natural gas properties located in Canada
"**CBM**" means coalbed methane
"**CERCLA**" means the Comprehensive Environmental Response, Compensation and Liability Act
"**DD&A**" means Depletion, Depreciation and Accretion
"**GHG**" means greenhouse gas
"**EPA**" means the U.S. Environmental Protection Agency
"**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 British Thermal Units, a measure of heating value, 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
"**MMcfed**" means MMcfe per day
"**NGL**" or "**NGLs**" means natural gas liquids
"**NYMEX**" means New York Mercantile Exchange
"**NYSE**" means New York Stock Exchange
"**Oil**" includes crude oil and condensate
"**Tcfe**" means trillion cubic feet 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
"**Alliance Leasehold**" means the natural gas leasehold and royalty interests acquired in the Alliance Acquisition and developed thereafter
"**Alliance Midstream Assets**" means the natural gas gathering network and processing facilities purchased by KGS from Quicksilver in January 2010
"**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
"**CMS Litigation**" means litigation against CMS Marketing Services and Trading Company concerning a gas supply contract under which we agreed to deliver 10 MMcfd at a floor price of $2.49 per Mcf
"**Eni**" means either or both Eni Petroleum US LLC and Eni US Operating Co. Inc., which are subsidiaries of Eni SpA

"**Eni Production**" means production attributable to Eni pursuant to the Eni Transaction

"**Eni Transaction**" means the June 19, 2009 conveyance of a 27.5% interest in our Alliance Leasehold

"**FASB**" means the Financial Accounting Standards Board, which promulgates accounting standards in the U.S.

"**FASC**" means the *FASB Accounting Standards Codification*, which is the single source of authoritative U.S. GAAP not promulgated by the SEC

"**GAAP**" means accounting principles generally accepted in the United States

"**Gas Purchase Commitment**" means the commitment pursuant to the Eni Transaction to purchase the Eni Production at $8.60 per MMBtu less costs related to gathering and processing

"**KGS**" means Quicksilver Gas Services LP, which is our publicly-traded partnership that trades under the ticker symbol "KGS"

"**KGS Credit Agreement**" means the KGS senior secured revolving credit facility

"**KGS IPO**" means the KGS initial public offering completed on August 10, 2007

"**KGS Secondary Offering**" means the public offering of 4,000,000 KGS common units on December 16, 2009 and the underwriters' option exercise to purchase an additional 549,200 KGS common units during January 2010

"**Mercury**" means Mercury Exploration Company, which is owned by members of the Darden family

"**Michigan Sales Contract**" means the gas supply contract which expired 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 BBEP in November 2007

"**RSU**" means restricted stock unit

"**SEC**" means the United States Securities and Exchange Commission

"**Senior Secured Credit Facility**" means our U.S. senior secured revolving credit facility and our Canadian senior secured revolving credit facility

"**Senior Secured Second Lien Facility**" means our $700 million five-year senior secured second lien facility which we entered into pursuant to the Alliance Transaction that we subsequently repaid and terminated in June 2009

INDEX TO ANNUAL REPORT ON FORM 10-K
For the Year Ended December 31, 2009

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.

Forward-Looking Information

Certain statements contained in this Annual 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 oil prices;
- failure or delays in achieving expected production from exploration and development projects;
- uncertainties inherent in estimates of natural gas, NGL and oil reserves and predicting natural gas, NGL and oil reservoir performance;
- effects of hedging natural gas, NGL and 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, including environmental and climate change requirements;
- the effects of existing or future litigation; and
- certain factors discussed elsewhere in this Annual 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. The forward-looking statements included in this Annual Report are made only as of the date of this Annual Report, and we undertake no obligation to update any of these forward-looking statements to reflect subsequent events or circumstances except to the extent required by applicable law.

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

PART I

ITEM 1. *Business*

GENERAL

Quicksilver Resources Inc., including its subsidiaries, is 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, Colorado, Wyoming and Montana, and Canada in Alberta and British Columbia, which had estimated total proved reserves of approximately 2.4 Tcfe at December 31, 2009. We have significant exploration activities in North America, principally in the Horn River Basin of Northeast British Columbia and the Green River Basin of Colorado. In addition, our new ventures team actively studies other basins in North America for unconventional natural gas opportunities which may yield future exploration opportunities. After completion of the KGS Secondary Offering, we own approximately 61% of KGS, a publicly-traded midstream master limited partnership controlled by us, and we also own approximately 40% of the limited partner units of BBEP, a publicly-traded oil and natural gas exploration and production master limited partnership.

Our common stock trades under the symbol "KWK" on the New York Stock Exchange. The units of KGS are publicly traded on the NYSE under the ticker symbol "KGS" and the units of BBEP are traded on the NASDAQ Global Select Market under the ticker symbol "BBEP."

FORMATION AND DEVELOPMENT OF BUSINESS

We were organized as a Delaware corporation in 1997 and became a public company in 1999. As of December 31, 2009, members of the Darden family and entities controlled by them, beneficially owned approximately 30% of our outstanding common stock.

STRATEGIC TRANSACTIONS

In August 2008, we completed the $1.3 billion Alliance Acquisition that consisted of producing and non-producing leasehold, royalty and midstream assets that we believe complements our existing operations in the Fort Worth Basin of North Texas. Consideration in the transaction was $1 billion in cash, which was financed with debt, and $262 million in Quicksilver common stock. We funded the cash portion of the transaction by drawing $675 million on our Senior Secured Second Lien Facility and drawing the remainder on our Senior Secured Credit Facility. At the time of the acquisition, there were 299 Bcf of proved natural gas reserves and considerable opportunities for increasing our proved reserves.

In June 2009, we completed the sale of a 27.5% working interest in our Alliance Leasehold to Eni for total proceeds of $280 million. In addition to the Alliance Leasehold, which includes approximately 13,000 acres in northern Tarrant and southern Denton counties of Texas, Quicksilver and Eni formed a strategic alliance for acquisition, development and exploitation of unconventional natural gas resources in an area covering approximately 270,000 acres surrounding the Alliance Leasehold. The sale represented approximately 121 Bcf of proved natural gas reserves as of April 1, 2009.

In January 2010, we completed the previously announced sale of our Alliance midstream assets to KGS for proceeds of $95.2 million. KGS funded the purchase with approximately $92 million of proceeds from the KGS Secondary Offering which reduced our ownership in KGS from 73% to 61%. In December 2008, we completed the sale of the Lake Arlington Dry System to KGS for proceeds of approximately $42 million. We believe the sale of these midstream assets to KGS enables us to maintain operating control and efficiently develop our natural gas properties while redeploying the associated capital into projects with higher expected returns. As KGS is included in our consolidated financial statements, these transactions had no effect on our total assets or results of operations.

BUSINESS STRATEGY

We have a multi-pronged strategy to increase share value through cost-effective growth in production and reserves by focusing on unconventional natural gas plays onshore in North America. This strategy takes advantage of our proven record and expertise in identifying and developing properties containing fractured shale, coalbed methane and tight sands. Our strategy includes the following key elements:

Focus on core areas of repeatable, low-risk development: We believe that operating in concentrated areas allows us to more efficiently deploy our resources, manage costs and leverage our base of technical expertise. We intend to invest the majority of our 2010 capital program in low-risk development and exploitation projects on our extensive leasehold positions in the Fort Worth and Western Canadian Sedimentary basins. In 2010, we expect to concentrate our development drilling primarily in our Barnett Shale properties in the Fort Worth Basin of North Texas, and to a lesser extent, in our CBM properties in Alberta, Canada.

Pursue disciplined organic growth opportunities: We intend to spend approximately 10% of our 2010 capital program in high-potential, longer cycle-time exploration projects to replenish our inventory of development projects for the future. Through our activities in the Fort Worth and Western Canadian Sedimentary basins, we have developed significant expertise in identifying, developing and producing fractured shales, coal seams and tight sands. We are focused on identifying and evaluating opportunities that allow us to apply this expertise and experience to the development and operation of other unconventional reservoirs in North America. In 2010, we will continue to focus our exploratory activities on our leasehold interests in the Horn River Basin of Northeast British Columbia where we hold a 100% working interest in 130,000 prospective acres. We also expect to continue exploratory activities in the Greater Green River Basin of northern Colorado and southern Wyoming where we hold a 75% working interest in approximately 105,000 acres. In addition, we may seek to acquire similar acreage positions for future exploration activities.

Enhance profitability through control and marketing of our equity natural gas and oil: We seek to maximize profitability by exercising control over the delivery of our production to distribution pipelines owned by third parties. We seek to achieve this by continuing to improve upon and add to our gathering and processing infrastructure. We believe this allows us to better manage the physical movement of our production and the costs of our operations by decreasing dependency on third parties. We also monitor the spot markets for commodities and seek to sell our uncommitted production into the most attractive markets. We continue to control our midstream operations in the Fort Worth Basin through our ownership of KGS.

Maintain flexible financial profile: We believe that a flexible financial structure enables us to capitalize on opportunities and to limit our financial risk. Our ownership interests in KGS and BBEP provide additional financial flexibility for the Company while enabling us to participate in the expected market growth of both these entities. In addition, to increase the predictability in the prices we receive for our natural gas and oil production, we hedge the commodity price of a substantial portion of our production with financial derivative instruments. We regularly review the credit-worthiness of our hedging counterparties, and our hedging program is spread among numerous financial institutions, all of which participate in our Senior Secured Credit Facility.

BUSINESS STRENGTHS

High-quality asset base with long reserve life: Our proved reserves of approximately 2.4 Tcfe as of December 31, 2009, were approximately 99% natural gas and NGLs and were 68% proved developed. The majority of these reserves are located in our core areas in the Fort Worth Basin in north Texas and the Western Canadian Sedimentary Basin in Alberta, which accounted for 89% and 10%, respectively, of our proved reserves. We believe our assets are characterized by long reserve lives and predictable well production profiles. Based on our annualized fourth-quarter 2009 average production from these properties, our implied reserve life (proved reserves divided by annualized fourth-quarter 2009 production) was 20.4 years and our implied proved developed reserve life (proved developed reserves divided by annualized fourth quarter 2009 production) was 13.9 years. As of December 31, 2009, we operated properties containing 99% of our proved reserves.

Multi-year inventory of development and exploitation drilling projects: As of December 31, 2009, we owned leases covering more than 500,000 net acres in our two core areas, of which approximately 34% were undeveloped. Within the Fort Worth Basin alone, we have identified more than 1,000 remaining drilling locations, which at the anticipated 2010 drilling rate; provide us with a 10-year inventory of drilling locations.

Our drilling success rate has averaged more than 99% during the past three years. We use 3D seismic data to enhance our ongoing drilling and development efforts as well as to identify new targets in both new and existing fields, and our seismic library covers more than 90% of our acreage in the Fort Worth Basin. For 2010, we expect our capital program will be approximately $340 million for drilling and completion activities in the Fort Worth Basin.

Proven record of organic growth in reserves and production: During the past three years, we have added approximately 1.0 Tcfe of proved reserves from organic development drilling activities. We have supplemented this activity with the Alliance Acquisition in 2008, which added 299 Bcfe of proved reserves at the time of its purchase. We also have divested approximately 546 Bcfe of proved reserves associated with our former Northeast Operations in 2007 and 121 Bcf of proved reserves associated with the Eni Transaction in 2009. Excluding acquisition and divestiture activity, we have replaced approximately 377% of our production during the three years ended December 31, 2009. Our growth has resulted from our ability to acquire attractive undeveloped acreage and apply our technical expertise to find, develop and produce reserves. In recent years, we have demonstrated this ability through our accomplishments in our two core areas. We believe our current acreage position will provide opportunities to continue our reserve and production growth.

Midstream strength: Our midstream operations, which are primarily owned or operated by KGS, are well positioned to complement our growth initiatives in the Fort Worth Basin and to compete with other midstream providers for unaffiliated business. Quicksilver's operational structure allows our midstream operations to more accurately forecast future gathering and processing estimates and to assess the need and timing for capacity additions. We believe KGS' assets in the Fort Worth Basin are well positioned to expand the gathering system footprint, increase throughput volumes and plant utilization which we believe will ultimately increase cash flows.

Experienced management and technical team: Our CEO, Glenn Darden, and our Chairman, Thomas Darden, are founding members of our company and have held executive positions at Quicksilver since our formation. They both have been in the oil and natural gas business their entire professional careers. Since our formation, they, along with an experienced executive management team, have successfully implemented a disciplined growth strategy with a primary focus on net asset value growth through the development of unconventional resources. Our executive management team is supported by a core team of technical and operational managers who have significant industry experience, including experience in drilling and completing horizontal wells and in unconventional reservoirs.

FINANCIAL INFORMATION ABOUT SEGMENTS AND GEOGRAPHICAL AREAS

The consolidated financial statements included in Item 8 of this Annual Report contain information on our segments and geographical areas, which is incorporated herein by reference.

PROPERTIES

Substantially all of our properties consist of interests in developed and undeveloped oil and natural gas leases and mineral acreage. In addition, we have midstream assets, including natural gas and NGL processing plants and related gathering and treating systems. Our midstream operations in the Fort Worth Basin are conducted by KGS, of which we own approximately 61% of the partnership interests, including 100% of its general partner. We also indirectly own interests in other oil and natural gas properties through our ownership of approximately 21.348 million limited partnership units in BBEP, representing approximately 40% of their partnership interests.

OIL AND NATURAL GAS OPERATIONS

Our oil and natural gas operations are focused onshore in North America, primarily in unconventional natural gas plays. Our current production and development operations are concentrated in the Fort Worth and Western Canadian Sedimentary basins. At December 31, 2009, we had estimated total proved reserves of approximately 2.4 Tcfe, 99% of which were natural gas and NGLs and 68% of which were proved developed. Approximately 89% of our reserves at December 31, 2009 were located in Texas and approximately 10% were in Canada. For 2009, we had average production of 324.5 MMcfe per day and total production of 118.5 Bcfe.

Since going public in 1999, we have grown our reserves and production at an approximate compound annual growth rate of 24% and 19%, respectively.

We believe that our 2010 and 2011 reserve and production growth will be through development of our leasehold interests in our core areas in Texas and Alberta. We anticipate our 2010 production volumes to average in the range of 390 MMcfe to 400 MMcfe and are expected to consist of approximately 80% natural gas and 20% NGLs and oil. In addition, we are actively exploring the Horn River Basin in British Columbia and the Green River Basin in Colorado and Wyoming. We may also pursue acquisitions of additional undeveloped leasehold interests, which could allow for further capitalization on our proven expertise in unconventional gas plays.

Texas

Our Barnett Shale properties in the Fort Worth Basin in North Texas contained 89% of our total estimated proved reserves and approximately 78% of our total average daily production came from these properties in 2009. In the fourth quarter of 2009, our net production from our Texas wells was approximately 251 MMcfed. We expect approximately 80% of our 2010 production to come from our Texas properties.

At December 31, 2009, we held approximately 162,000 net acres in the Fort Worth Basin of which approximately 40% is currently developed. We have identified more than 1,000 remaining potential drilling locations in the Fort Worth Basin. Much of our acreage in Hood and Somervell counties contains high-Btu natural gas which contains NGLs within the natural gas stream. We gather our production and process the high-Btu natural gas through a midstream system that is primarily owned and operated by KGS.

KGS manages a network of natural gas gathering pipelines, ranging up to 20 inches in diameter, all located in the Fort Worth Basin. Additionally, KGS owns a NGL pipeline that interconnects with pipelines owned by third parties. The pipeline system gathers and delivers natural gas produced by our wells and those of third parties to the processing facilities. We expect to continue to construct additional gathering assets as additional wells in the Fort Worth Basin are developed. Our capital program for 2010 includes approximately $92 million for midstream assets, including $80 million to be funded by KGS.

During 2009, we drilled 156 gross (95.2 net) wells in the Fort Worth Basin primarily from multi-well drilling pads. On these multi-well pads, all the wells are drilled prior to initiating completion activities. At December 31, 2009, we had drilled a total of 874 gross (727.5 net) wells in the Fort Worth Basin since we began exploration and development operations in 2003. In 2009, we completed 97 gross (67.4 net) wells and tied 112 gross (82.6 net) wells into sales.

The portion of the 2010 capital program allocated to our Texas interests is approximately $340 million. At December 31, 2009, we had five drilling rigs operating for us in the Fort Worth Basin, but we expect to utilize four rigs in this area during most of 2010.

Rocky Mountain Region

Our Rocky Mountain producing properties are located primarily in Montana and Wyoming. Production from those properties is primarily oil from established formations at depths ranging from 1,000 feet to 17,000 feet. At December 31, 2009, our Rocky Mountain proved reserves were approximately 2.1 MMBbls of oil and 1.6 MMcfe of natural gas and NGLs for total equivalent reserves of 14 Bcfe. Daily production from our properties in the Rocky Mountain region averaged 5.4 MMcfed for 2009. We also hold a 75% working interest in approximately 105,000 acres (78,000 net) in the Greater Green River Basin of northern Colorado and southern Wyoming where we are currently conducting exploratory activities.

Canada

At December 31, 2009, Canadian reserves of 253 Bcfe, primarily attributable to our CBM projects in Alberta, comprised 10% of our total proved reserves. Canadian production averaged 66.9 MMcfed, representing approximately 20% of our total 2009 production. Canadian production averaged 69 MMcfed during the fourth quarter of 2009.

As of December 31, 2009, we had approximately 100,000 gross (72,000 net) undeveloped acres in Alberta, Canada. In Alberta, we had 2009 capital expenditures of approximately $24.2 million which included the drilling of 141 gross (36.1 net) productive wells with 179 gross (67.5 net) wells tied into sales in 2009. During 2010, we expect to drill approximately 36 gross (29 net) wells, and similar to 2009, we expect to totally fund these activities by cash flows from Canadian operations.

We also have approximately 130,000 prospective acres in the Horn River Basin of Northeast British Columbia. During 2009, we spent $62.1 million for exploration and facilities and infrastructure in the Horn River Basin where we have drilled and cased two wells. The first well, which evaluated the Muskwa formation, began producing in the third quarter of 2009 and the second well, which evaluated the Klua formation, commenced producing late in the fourth quarter of 2009. We expect to drill two wells and complete one additional well in the Horn River Basin in 2010. We also entered into a nine-year agreement with a third party that began in May 2009 for the firm processing and transportation of natural gas out of the Horn River Basin with initial volumes of 3 MMcfd increasing to 100 MMcfd by May 2013.

2010 Capital Program

We intend to focus our capital spending program primarily on the continued development of our properties in Texas and Alberta. For 2010, we have established a capital program of $540 million, of which we have allocated $390 million for drilling and completion activities, $92 million for gathering and processing facilities (including approximately $80 million to be funded directly by KGS), $53 million related to acquisition of additional leasehold interests and $5 million for other property and equipment. On a regional basis, approximately $465 million has been allocated to Texas to drill approximately 100 wells on operated properties and to complete and tie in approximately 130 wells. Canada has been allocated $52 million to maintain current production levels and continue exploratory activities in the Horn River Basin through the drilling of approximately 38 gross (31 net) wells. The remaining capital program is spread among our other operating areas. Our capital program for gathering and processing expenditures for Texas is $92 million, including $80 million to be funded by KGS, and $7 million for Canada.

OIL AND NATURAL GAS RESERVES

In December 2008, the SEC adopted its final rule for "Modernization of Oil and Gas Reporting." The most significant changes incorporated into our proved reserve process and related disclosures for 2009 include:

- the use of an unweighted average of the preceding 12-month first-day-of-the-month prices for determination of proved reserve values included in calculating full cost ceiling limitations and for annual proved reserve disclosures;
- limitations regarding the types of technologies that may be used to reliably establish the classification of proved reserves;
- reporting of investments and progress made during the year to convert proved undeveloped reserves to proved developed reserves; and,
- reporting on the independence and qualifications of our personnel and independent petroleum engineers who are responsible for the preparation of our reserve estimates.

Our proved reserve estimates and related disclosures for 2009 are presented in compliance with this new guidance. Our 2008 and 2007 proved reserve estimates and related disclosures were prepared in compliance with the SEC guidance then in effect.

The process of estimating natural gas, NGL and oil reserves is complex. In order to prepare these estimates, we developed, maintain and monitor our internal processes and controls for estimating and recording reserves in compliance with the SEC rule. Compliance with the SEC reserve guidelines is the primary responsibility of our reservoir engineering team. We require that reserve estimates be made by qualified reserve estimators, as defined by the Society of Petroleum Engineers' standards. Our reservoir engineering team participates in continuing education to maintain a current understanding of SEC reserve reporting requirements.

Our reservoir engineering team, led by our Vice President - Reservoir Engineering, is responsible for preparation and maintenance of our engineering data and review of proved reserve estimates with our independent petroleum engineers. Our Vice President - Reservoir Engineering has over 20 years experience in the oil and gas industry. The reservoir engineering team reports directly to our Executive Vice President - Operations and is otherwise independent from management for our operating areas. Throughout the year, the reservoir engineering team analyzes the performance of producing properties for each operating area, identifies significant reserve additions and revisions and prepares internal proved reserve estimates. In addition, they are responsible for maintenance of all reserve engineering data. Integrity of reserve engineering data is maintained through restricting full access only to the members of our reservoir engineering team. Other personnel have read-only access or no access to reserve engineering data.

Our U.S. and Canadian estimated proved reserves and future net cash flows have been prepared by Schlumberger Data and Consulting Services ("Schlumberger") and LaRoche Petroleum Consultants, Ltd. ("LaRoche"), respectively. The Schlumberger technical team responsible for calculating our U.S. reserves has extensive experience in reservoir evaluation and reserve analysis for tight gas sand, fractured shale and coalbed methane projects. The LaRoche technical team responsible for calculating our Canadian reserves has extensive experience in international reservoir evaluation and reserve analysis including coalbed methane projects. Prior to finalizing their reserve estimates, the independent petroleum engineers' results are reviewed in detail by our reservoir engineering team. Reports of our estimated proved reserves prepared by these independent petroleum engineers have been reviewed by our Vice - President Reservoir Engineering and executive management team.

The Audit Committee of our Board of Directors meets with executive management, our Vice President - Reservoir Engineering and the independent petroleum engineers to discuss the process of and results of reserve estimation. During 2009, we implemented enhancements to our analytical review of reserve estimates to include comparisons of our ending proved undeveloped estimates to our median ending ultimate recoverable reserves for each of our operating areas and sub-areas. We also implemented additional reviews of drilling results and proved undeveloped estimates with our executive management team and our Audit Committee.

Proved oil and natural gas reserves are the estimated quantities of oil, natural gas, and NGLs which through analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic conditions and operating methods. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil, natural gas and NGLs actually recovered will equal or exceed the estimate. To achieve reasonable certainty, the technologies used in the estimation process have been demonstrated to yield results with consistency and repeatable. Proved developed oil and natural gas reserves are expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped oil and natural gas reserves are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for re-completion. Proved reserves for undrilled wells are estimated only where it can be demonstrated that there is continuity of production from the existing productive formation.

The reserve data presented below are only estimates and are subject to inherent uncertainties. The determination of oil and natural gas reserves is based on estimates that are highly complex and interpretive. Reserve engineering is a subjective process that depends upon the quality of available data and on engineering and geological interpretation and judgment. Although we believe the reserve estimates contained in this Annual Report are reasonable, reserve estimates are imprecise and are expected to change as additional information becomes available. Additional information regarding risks associated with our proved estimated proved oil and gas reserves may be found in Item 1A of this Annual Report.

The following table summarizes our proved reserves and the standardized measure of discounted future net cash flows attributable to them at December 31, 2009 in accordance with the rules established by the SEC. Our estimates of proved oil and gas reserves at December 31, 2008 and 2007 were prepared in compliance with SEC requirements then in effect.

	Proved Developed Reserves			Proved Undeveloped Reserves			Total Proved Reserves		
	For The Years Ended December 31,			For The Years Ended December 31,			For The Years Ended December 31,		
	2009	2008	2007	2009	2008	2007	2009	2008	2007
Natural gas (MMcf)									
United States	1,044,140	756,191	379,917	511,894	550,306	282,492	1,556,034	1,306,497	662,409
Canada	223,300	278,668	260,029	29,753	53,903	68,352	253,053	332,571	328,381
Total	1,267,440	1,034,859	639,946	541,647	604,209	350,844	1,809,087	1,639,068	990,790
NGL (MBbl)									
United States	60,997	56,181	50,738	37,264	35,746	39,317	98,261	91,927	90,055
Canada	13	8	10	-	-	-	13	8	10
Total	61,010	56,189	50,748	37,264	35,746	39,317	98,274	91,935	90,065
Oil (MBbl)									
United States	2,467	2,509	2,763	392	405	311	2,859	2,914	3,074
Canada	-	-	-	-	-	-	-	-	-
Total	2,467	2,509	2,763	392	405	311	2,859	2,914	3,074
Total (MMcfe)									
United States	1,424,924	1,108,331	700,923	737,830	767,212	520,260	2,162,754	1,875,543	1,221,183
Canada	223,378	278,716	260,089	29,753	53,903	68,352	253,131	332,619	328,441
Total	1,648,302	1,387,047	961,012	767,583	821,115	588,612	2,415,885	2,208,162	1,549,624

	Years Ended December 31,		
	2009 (1)	2008 (2)	2007 (2)
Representative prices:			
Natural gas – Henry Hub	$ 3.87	$ 5.71	$ 6.80
Natural gas – AECO	3.76	5.44	6.35
NGL – Mont Belvieu, Texas	24.94	21.65	57.35
Oil – WTI Cushing	61.18	44.60	95.98
Standardized measure of discounted future net cash flows (3), after income tax (in millions)	$ 1,182.7	$ 1,794.3	$ 2,169.2

(1) The natural gas and crude oil prices as of each respective year end were based, respectively, on the unweighted average of the preceding 12-month first-day-of-the-month NYMEX Henry Hub and AECO prices per MMBtu and NYMEX prices per Bbl, adjusted to reflect local differentials.

(2) The natural gas and oil prices as of December 31, 2008 and 2007 were based, respectively, on last day-of-the-year price for NYMEX Henry Hub and AECO price per MMBtu and NYMEX price per Bbl, adjusted to reflect local differentials.

(3) Determined based on year end unescalated costs in accordance with the guidelines of the SEC, discounted at 10% per annum.

PROVED UNDEVELOPED RESERVES

As of December 31, 2009, we had total proved undeveloped reserves of 767.6 Bcfe comprised of 737.8 Bcfe in Texas on 281 well locations and 29.8 Bcfe in Alberta, Canada on 260 well locations. All of the 541 well locations are slated for development before the end of 2014.

Our 2009 drilling and completion activities related to our December 31, 2008 proved undeveloped locations were as follows:

	For The Year Ended December 31, 2009					
	Drilled		Completions		Producing	
	Gross	Net	Gross	Net	Gross	Net
United States	66.0	39.9	23.0	10.9	18.0	10.6
Canada	37.0	18.6	30.0	14.1	24.0	10.1
Total	103.0	58.5	53.0	25.0	42.0	20.7

Our gross capital costs for a Texas Barnett Shale well from preparation of the multi-well drilling pad through the initiation of production generally range from $2.0 million to $5.0 million depending on factors such as the area, the depth and lateral length of each well and its distance to central facilities. On each multi-well drilling pad, we drill all the wells prior to initiation of completion activities. As a result, we maintain an inventory of drilled wells awaiting completion. During 2010, we expect to spend $268.2 million to drill, complete and tie-in wells on proved locations.

In Alberta, the gross capital costs for a typical CBM well from pre-drilling preparation through the initiation of production generally range from $0.2 million to $0.4 million depending upon number of coal seams, depth and distance to a gathering system. As our drilling and completion operations are limited by the restriction of the movement of rigs and other equipment due to wet weather and spring thaw, we expect to maintain an inventory of drilled wells awaiting completion and completed wells awaiting tie-in to sales lines. During 2010, we expect to spend capital of $7.7 million to drill, complete and tie-in wells on proved locations.

At December 31, 2009, none of our inventory of proved undeveloped drilling locations has been recognized as proved reserves for five years or longer. Currently, we anticipate that all our proved undeveloped reserves will be developed prior to the end of 2014.

DEVELOPMENT AND EXPLORATION ACTIVITIES AT YEAR-END

At December 31, 2009, we had five drilling rigs under lease in Texas, including one rig operating on a proved undeveloped location, two rigs operating on unproved locations and two rigs mobilizing, to a proved undeveloped location and an unproved well location. Additionally, completion work was in progress on five proved Texas wells with 207 (153.9 net) wells awaiting completion or tie-in to sales. One drilling rig was operating on an unproved location in British Columbia and 189 wells (129.0 net) in Alberta were awaiting completion or tie-in to sales lines.

DRILLING ACTIVITY

During the periods indicated, we drilled the following exploratory and development wells:

	Years Ended December 31,					
	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Development:						
United States						
Productive [(1)]	154.0	93.2	292.0	255.7	258.0	226.2
Non-productive . . .	-	-	1.0	1.0	-	-
Canada						
Productive [(2)]	141.0	36.1	372.0	155.9	351.0	179.1
Non-productive . . .	-	-	1.0	1.0	-	-
Total	295.0	129.3	666.0	413.6	609.0	405.3
Exploratory:						
United States						
Productive	4.0	4.0	5.0	4.1	32.0	19.2
Non-productive . . .	-	-	2.0	2.0	4.0	3.2
Canada						
Productive	2.0	2.0	-	-	5.0	5.0
Non-productive . . .	-	-	-	-	-	-
Total	6.0	6.0	7.0	6.1	41.0	27.4
Total:						
Productive	301.0	135.3	669.0	415.7	646.0	429.5
Non-productive . . .	-	-	4.0	4.0	4.0	3.2
Total	301.0	135.3	673.0	419.7	650.0	432.7

(1) U.S. development drilling includes non-operated drilling of 37 wells (3.0 net), 36 wells (16.1 net) and 14 wells (7.2 net) for 2009, 2008 and 2007, respectively.

(2) Canadian development drilling includes non-operated drilling of 88 wells (8.1 net), 170 wells (15.3 net) and 130 wells (16.1 net) for 2009, 2008 and 2007, respectively.

VOLUMES, SALES PRICES AND OIL AND GAS PRODUCTION EXPENSE

The discussion of volumes produced from revenue generated by and cost associated with operating our properties included in Management's Discussion and Analysis in Item 7 of this Annual Report is incorporated herein by reference.

DELIVERY COMMITMENTS AND PURCHASERS OF NATURAL GAS, NGLs AND OIL

We have a written commitment to provide a third-party 25,332 MMBtud through July 2019 at market-based prices for delivery at the Gulf Crossing Pipeline from the Crosstex North Texas Pipeline. We expect to deliver our natural gas production as well as natural gas attributable to third parties from our Alliance wells. For the month ended December 31, 2009, we sold approximately 90,000 MMBtud from our Alliance wells. We expect production from our Alliance properties to increase as we continue to develop our leasehold interests in the area through 2012 and beyond. Additionally, we estimate that we had approximately 70,000 MMBtud available for delivery under the commitment from our oil and gas interests in the Barnett

Shale in the Fort Worth Basin. We currently have no other firm commitments for the sale of our Barnett Shale production for a period longer than 12 months.

We sell natural gas, NGLs and oil to a variety of customers, including utilities, major oil and natural gas companies or their affiliates, industrial companies, large trading and energy marketing companies and other users of petroleum products. Because our products are commodity products sold primarily on the basis of price and availability, we are not dependent upon one purchaser or a small group of purchasers. Accordingly, the loss of any single purchaser would not materially affect our revenue. During 2009, Louis Dreyfus Natural Gas Corp., Dynegy Liquids Marketing and Trading and BG Energy Merchants, the largest purchasers of our products, accounted for approximately 15%, 13% and 10% of our total natural gas, NGL and oil revenue, respectively.

ACQUISITION, EXPLORATION AND DEVELOPMENT CAPITAL EXPENDITURES

The following table summarizes our acquisition, exploration and development costs incurred:

	United States	Canada (In thousands)	Consolidated
2009			
Proved acreage	$ 118	$ -	$ 118
Unproved acreage	11,300	2,658	13,958
Development costs	341,658	24,179	365,837
Exploration costs	32,798	59,402	92,200
Total	$ 385,874	$ 86,239	$ 472,113
2008			
Proved acreage	$ 787,172	$ -	$ 787,172
Unproved acreage	484,770	54,048	538,818
Development costs	836,032	68,629	904,661
Exploration costs	30,161	10,280	40,441
Total	$ 2,138,135	$ 132,957	$ 2,271,092
2007			
Proved acreage	$ -	$ -	$ -
Unproved acreage	17,031	31,448	48,479
Development costs	648,632	67,608	716,240
Exploration costs	75,862	11,953	87,815
Total	$ 741,525	$ 111,009	$ 852,534

PRODUCTIVE OIL AND GAS WELLS

The following table summarizes productive wells:

	As of December 31, 2009			
	Natural Gas		Oil	
	Gross	Net	Gross	Net
United States	834.0	697.0	198.0	194.0
Canada	2,815.0	1,297.3	4.0	0.1
Total	3,649.0	1,994.3	202.0	194.1

OIL AND GAS ACREAGE

Our principal natural gas and oil properties consist of non-producing and producing oil and gas leases and mineral acreage, including reserves of natural gas and oil in place. Developed acres are defined as acreage allocated to wells that are producing or capable of producing. Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial reserves, regardless of whether such acreage contains proved reserves. Gross acres are the total number of acres in which we have a working interest. Net acres are the sum of our fractional interests owned in the gross acres.

The following table indicates our interest in developed and undeveloped acreage:

	As of December 31, 2009			
	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
Texas	75,752	66,376	553,800	468,491
Other	116,988	107,973	198,732	154,090
United States	192,740	174,349	752,532	622,581
Canada	458,933	272,693	249,231	222,524
Total	651,673	447,042	1,001,763	845,105

The following table summarizes information regarding the total number of net undeveloped acres as of December 31, 2009:

		2010 Expirations		2011 Expirations		2012 Expirations	
	Net Undeveloped Acres	Net Acres	Net Acres with Options to Extend	Net Acres	Net Acres with Options to Extend	Net Acres	Net Acres with Options to Extend
Texas	468,491	352,858	22,236	54,967	1,032	18,580	2,378
Other U.S.	154,090	28,773	128	28,219	5,628	16,171	-
Canada	222,524	25,379	-	70,043	-	83,006	-
Totals	845,105	407,010	22,364	153,229	6,660	117,757	2,378

All of the acreage scheduled to expire can be held through drilling operations. We believe that we have the ability to retain all of the expiring acreage that we feel will provide economic production either through drilling activities or through the exercise of extension options.

COMPETITION

We compete for acquisitions of prospective oil and natural gas properties and oil and gas reserves. We also compete for drilling rigs and equipment used to drill for and produce oil and gas. Our competitive position is dependent upon our ability to recruit and retain geological, engineering and management expertise. We believe that the location of our leasehold acreage, our exploration and production expertise and the experience and knowledge of our management enable us to compete effectively in our core operating areas. However, we face competition from a substantial number of other companies, many of which have larger technical staffs and greater financial and operational resources than we do and from companies in other, but potentially related, industries.

GOVERNMENTAL REGULATION

Our operations are affected from time to time in varying degrees by political developments and U.S. and Canadian federal, state, provincial and local laws and regulations. In particular, natural gas and oil production and related operations are, or have been, subject to price controls, taxes and other laws and regulations relating to the industry. Failure to comply with such laws and regulations can result in substantial penalties. The regulatory burden on the industry increases our cost of doing business and affects our profitability. We do not anticipate any significant challenges in complying with laws and regulations applicable to our operations.

SAFETY REGULATION

We are subject to a number of federal, provincial and state laws and regulations, whose purpose is to protect the health and safety of workers, both generally and within our industry. Regulations overseen by OSHA, the EPA and other agencies require, among other matters, that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We are also subject to safety regulations which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals.

ENVIRONMENTAL MATTERS

We are subject to stringent and complex U.S. and Canadian federal, state, provincial and local environmental laws, regulations and permits and international environmental conventions, including those relating to the generation, storage, handling, use, disposal, movement and remediation of natural gas, NGLs, oil and other hazardous materials; the emission and discharge of such materials to the ground, air and water; wildlife protection; the storage, use and treatment of water; and the placement, operation and reclamation of wells. These requirements are a significant consideration for us as our operations involve the generation, storage, handling, use, disposal, movement and remediation of natural gas, NGLs, oil and other hazardous or regulated materials and the emission and discharge of such materials to the environment. If we violate these requirements, or fail to obtain and maintain the necessary permits, we could be fined or otherwise sanctioned, which sanctions could include the imposition of fines and penalties and orders enjoining future operations. Pursuant to such laws, regulations and permits, we have made and expect to continue to make capital and other compliance expenditures.

We could be liable for any environmental contamination at our or our predecessors' currently or formerly owned or operated properties or third party waste disposal sites. Certain environmental laws, including CERCLA, more commonly known as Superfund, impose joint and several strict liability for releases of hazardous substances at such properties or sites, without regard to fault or the legality of the original conduct. In addition to potentially significant investigation and remediation costs, environmental contamination can give rise to claims from governmental authorities and other third parties for fines or penalties, natural resource damages, personal injury and property damage. State regulators in Texas are also becoming increasingly focused on air emissions from our industry, including volatile organic compound emissions. This increased scrutiny could lead to heightened enforcement of existing regulations as well as the imposition of new measures to control our emissions or curtail our operations.

Environmental laws, regulations and permits, and the enforcement and interpretation thereof, change frequently and generally have become more stringent over time. For example, various U.S. federal and state initiatives are underway to regulate, or further investigate the environmental impacts of, hydraulic fracturing. Such initiatives could require us to disclose the chemicals we use in the fracturing process, which disclosure may result in increased scrutiny or third party claims, or otherwise result in operational delays, liabilities and increased costs. In addition, from time to time, initiatives are proposed that could further regulate certain exploration and production by-products as hazardous wastes and subject them to more stringent requirements. If enacted, such initiatives could require us to incur substantial costs for compliance.

GHG emission regulation is also becoming more stringent. We are currently required to report annual GHG emissions from some of our operations, and additional GHG emission related requirements are in various stages of development. For example, the U.S. Congress is considering legislation that would establish a nationwide cap-and-trade system for GHGs, and the EPA has proposed regulating GHG emissions from stationary sources pursuant to the Prevention of Significant Deterioration and Title V provisions of the federal Clean Air Act which might require us to modify existing or obtain new air permits or install emission control technology. Any regulation of GHG emissions, including through a cap-and-trade system, technology mandate, emissions tax, reporting requirement or other program, could restrict our operations and subject us to significant costs, including those relating to emission credits, pollution control equipment, monitoring and reporting. Although there is still significant uncertainty surrounding the scope, timing and effect of future GHG regulation, any such regulation could have a material adverse impact on our business, financial condition, reputation and operating performance.

In addition, to the extent climate change results in warmer temperatures or more severe weather, our operations may be disrupted. For example, storms in the Gulf of Mexico could damage downstream pipeline infrastructure causing a decrease in takeaway capacity and potentially requiring us to curtail production. In addition, warmer temperatures might shorten the time during winter months when we can access certain remote production areas resulting in decreased exploration and production activity.

AVAILABILITY OF REPORTS AND CORPORATE GOVERNANCE DOCUMENTS

We make available free of charge on our internet website, www.qrinc.com, our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file or furnish such material to the SEC. Additionally, charters for the committees of our Board and our Corporate Governance Guidelines and Code of Business Conduct and Ethics can be found on our internet website under the heading "Corporate Governance." Our website and the information contained therein or connected thereto shall not be deemed to be incorporated into this Annual Report.

EMPLOYEES

As of February 15, 2010, we had 596 employees, none of whom have collective bargaining agreements.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following information is provided with respect to our executive officers as of February 15, 2010.

Name	Age	Position(s)
Thomas F. Darden	56	Director, Chairman of the Board
Glenn Darden	54	Director, President and Chief Executive Officer
Anne Darden Self	52	Director, Vice President - Human Resources
Jeff Cook	53	Executive Vice President - Operations
Philip W. Cook	48	Senior Vice President - Chief Financial Officer
John C. Cirone	60	Senior Vice President, General Counsel and Secretary
John C. Regan	40	Vice President, Controller and Chief Accounting Officer
Robert N. Wagner	46	Vice President - Reservoir Engineering

Officers are elected by our Board of Directors and hold office at the pleasure of the Board until their successors are elected and qualified. Thomas F. Darden, Glenn Darden and Anne Darden Self are siblings. Messrs. Jeff Cook and Philip W. Cook are not related. The following biographies describe the business experience of our executive officers:

THOMAS F. DARDEN has served on our Board of Directors since December 1997 and became Chairman of the Board in March 1999. He was elected as a director of Quicksilver Gas Services GP LLC in July 2007. Mr. Darden was previously employed by Mercury Exploration Company for 22 years in various executive level positions.

GLENN DARDEN has served on our Board of Directors since December 1997 and became our Chief Executive Officer in December 1999. He was elected as a director of Quicksilver Gas Services GP LLC in March 2007. He served as our Vice President until he was elected President and Chief Operating Officer in March 1999. Prior to that time, he served with Mercury for 18 years, the last five as Executive Vice President. Mr. Darden previously worked as a geologist for Mitchell Energy Company LP (subsequently merged with Devon Energy).

ANNE DARDEN SELF has served on our Board of Directors since September 1999, and became our Vice President – Human Resources in July 2000. She is also currently President of Mercury, where she has worked since 1992. From 1988 to 1991, she was employed by Banc PLUS Savings Association in Houston, Texas, initially as Marketing Director and for three years thereafter as Vice President of Human Resources. She worked from 1987 to 1988 as an Account Executive for NW Ayer Advertising Agency. Prior to 1987, she spent several years in real estate management.

JEFF COOK became our Executive Vice President – Operations in January 2006, after serving as our Senior Vice President – Operations since July 2000. From 1979 to 1981, he held the position of Operations Supervisor with Western Company of North America. In 1981, he became a District Production

Superintendent for Mercury Production Company and became Vice President of Operations in 1991 and Executive Vice President in 1998 of Mercury Production Company before joining us.

PHILIP W. COOK became our Senior Vice President – Chief Financial Officer in October 2005. From October 2004 until October 2005, Mr. Cook served as President and Chief Financial Officer of a private chemical company. From August 2001 until September 2004, he served as Vice President and Chief Financial Officer of a private oilfield service company. From August 1993 to July 2001, he served in various capacities, including Vice President and Controller, Vice President and Chief Information Officer and Vice President of Audit, of Burlington Resources Inc. (subsequently merged with ConocoPhillips), a public independent oil and gas company engaged in exploration, development, production and marketing.

JOHN C. CIRONE was named as our Senior Vice President, General Counsel and Secretary in January 2006, after serving as our Vice President, General Counsel and Secretary since July 2002. Mr. Cirone was employed by Union Pacific Resources (subsequently merged with Anadarko Petroleum Corporation) from 1978 to 2000. During that time, he served in various positions in the Law Department, and from 1997 to 2000 he was the Manager of Land and Negotiations. In 2000, he became Assistant General Counsel of Union Pacific Resources. After leaving Union Pacific Resources in August 2000, Mr. Cirone was engaged in the private practice of law prior to joining us in July 2002.

JOHN C. REGAN became our Vice President, Controller and Chief Accounting Officer in September 2007. He is a Certified Public Accountant with more than 15 years of combined public accounting, corporate finance and financial reporting experience. Mr. Regan joined us from Flowserve Corporation where he held various management positions of increasing responsibility from 2002 to 2007, including Vice President of Finance for the Flow Control Division and Director of Financial Reporting. He was also a senior manager specializing in the energy industry in the audit practice of PricewaterhouseCoopers, where he was employed from 1994 to 2002.

ROBERT N. WAGNER became our Vice President – Reservoir Engineering in December 2002, after serving as our Vice President – Engineering since July 1999. From January 1999 to July 1999, he was our manager of eastern region field operations. From November 1995 to January 1999, Mr. Wagner held the position of District Engineer with Mercury. Prior to 1995, he was with Mesa, Inc. (subsequently merged with Parker and Parsley) for more than eight years and served as both drilling engineer and production engineer.

ITEM 1A. Risk Factors

You should carefully consider the following risk factors together with all of the other information included in this Annual Report, 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 Annual Report could have a material adverse effect on our business, financial position, results of operations and cash flows.

Natural gas, NGL and 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 oil prices. These prices also affect the amount of cash flow available to service our debt, fund our capital program and 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 expected future prices. Lower prices may also reduce the amount of natural gas, NGLs and oil that we can economically produce.

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

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

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

If natural gas, NGL or 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 oil and natural gas reserves are capitalized and accumulated in separate country cost centers for the U.S. and Canada. These capitalized costs are amortized based on production for each country cost center. Each capitalized cost pool cannot exceed the net present value of the underlying natural gas, NGL and oil reserves. Impairment to the carrying value of our oil and gas properties was recognized in the fourth quarter of 2008 and the first, second and fourth quarters of 2009 and could occur again in the future if natural gas, NGL or oil prices utilized in determining reserve values cause the value of our reserves to decrease. Increased operating and capitalized costs without incremental increases in reserves value 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 non-cash expense, 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 oil reserves is complex. In order to prepare these estimates, we and our independent reserve engineers must project future production rates and timing of future 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. In additions to interpreting available technical data, we must also analyze other 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.

Actual future production, natural gas, NGL and oil prices and revenue, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and 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 our filings with the SEC. 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, 2009, approximately 32% of our estimated proved reserves were undeveloped. Recovery of undeveloped reserves requires additional capital expenditures and successful drilling and completion operations. Our reserve estimates assume that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of our reserves using SEC requirements, actual prices and costs may vary from these estimates, development may not occur as scheduled or actual results may not be as estimated prior to drilling.

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 oil reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are based on prices determined on an unweighted average of the preceding 12-month first-day-of-the-month prices adjusted for local differentials and operating and development costs as of period end. Actual future prices and costs may be materially higher or lower than the prices and costs used in our estimate. Any changes in consumption by natural gas, NGL and oil purchasers or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the costs from the development and production of natural gas and 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 our reserves' actual fair value.

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

Approximately 78% of our 2009 production was from Texas and approximately 20% was from Alberta, Canada. Because of our concentration in these geographic areas, any regional events that increase costs, reduce or disrupt availability of equipment or supplies, reduce demand or limit production, including weather and natural disasters, may impact us more significantly 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 U.S. 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, aboriginal claims, changes in laws and policies governing operations of foreign-based companies, currency restrictions and exchange rate fluctuations. For example, in addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by government regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced. Laws and policies of the United States affecting foreign trade and taxation may also adversely affect our Canadian operations.

In addition, the level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing our activity levels. Also, certain of our oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Therefore, seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity.

If we are unable to obtain needed capital or financing on satisfactory terms, our ability to replace our reserves or to maintain current production levels may be limited.

Historically, we have used our cash flow from operations, borrowings under our Senior Secured Credit Facility and issuances of equity and debt to fund our capital program, working capital needs and acquisitions. Our capital program may require additional financing above the level of cash generated by our operations to fund our growth. If our cash flow from operations decreases as a result of lower petroleum prices or otherwise, our ability to expend the capital necessary to replace our reserves or to maintain current production may be limited, resulting in decreased production over time. If our cash flow from operations is insufficient to satisfy our financing needs, we cannot be certain that additional financing will be available to us on acceptable terms or at all. Our ability to obtain bank financing or to access the capital markets for future equity or debt offerings may be limited by our financial condition or general economic conditions at the time of any such financing or offering. Even if we are successful in obtaining the necessary funds, the terms of such financings could have a material adverse effect on our business, results of operations and financial condition. If 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.

Our business involves many hazards and operational risks, some of which may not be insurable. The occurrence of a significant accident or other event that is not insured or not adequately insured could curtail our operations and have a material adverse effect on our business, results of operations and financial condition.

Our operations are subject to many risks inherent in the oil and natural gas industry, including operating hazards such as well blowouts, explosions, uncontrollable flows of 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 production depends on the proximity of reserves to, and the capacity of, natural gas and oil gathering systems, treatment plants, pipelines and trucking or terminal facilities.

U.S. and Canadian federal, state, local and provincial regulation relating to 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 oil.

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. Some of our insurance policies cover our subsidiaries, including KGS. As a result, if a named insured's claim is paid under such policy it would reduce the coverage available to us. We are not insured against all environmental incidents, claims or damages that might occur. Any significant accident or event that is not adequately insured could adversely affect our business, results of operations and financial condition. In addition, we may be unable to economically obtain or maintain the insurance that we desire. As a result of market conditions, premiums and deductibles for certain of our insurance policies could escalate further. In some instances, certain insurance could become unavailable or available only at reduced coverage levels. Any type of catastrophic event could have a material adverse effect on our business, results of operation and financial condition.

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 purchase proved reserves. In order to increase reserves and production, we must continue our development drilling or undertake other replacement activities. We strive 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 40% 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. BBEP suspended distributions for all of 2009 and will not resume distributions until the first quarter and payable the second quarter of 2010.

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. In the event of impairment of our BBEP units, we reduce the carrying value of our BBEP units and recognize non-cash expense, 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. Although we have diminished control over KGS' assets and operations, we are 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, liquids fractionation and transportation facilities we do not own or operate.

We deliver our production to market through gathering, fractionation and transportation systems that we do not own. Since we do not own or operate these assets, their continuing operation is not within our control.

If any of these pipelines and other facilities becomes unavailable or capacity constrained, it could have a material adverse effect on our business, financial condition and results of operations.

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 adversely affect our ability to operate our business.

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 and 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 better able to absorb the burden of any changes in federal, state, provincial and local laws and regulations than we can, which would adversely affect our competitive position. These competitors may be able to pay more for exploratory prospects and producing 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 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.

If market prices for our production exceed collar ceilings or swap prices, we would be required to make monthly cash payments, which could materially adversely affect our liquidity. If we choose not to engage in hedging arrangements in the future, we could be more affected by changes in natural gas, NGL and 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 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 difficulty in obtaining, or material increases in the cost of, drilling equipment, crews and associated supplies, equipment and services. In addition, drilling operations may be curtailed, delayed or canceled as a result of unexpected drilling conditions, including urban drilling, and possible title issues. Any such delays and price increases could adversely affect our ability to execute our drilling program and our results of operations and financial condition.

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

Our 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; 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 oil wells below actual production capacity to conserve supplies of natural gas and oil. We also are subject to changing and extensive tax laws, the effects of which cannot be predicted.

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.

We are subject to environmental laws, regulations and permits, including greenhouse gas requirements that may expose us to significant costs, liabilities and obligations.

We are subject to stringent and complex U.S. and Canadian federal, state, provincial and local environmental laws, regulations and permits and international environmental conventions, relating to, among other things, the generation, storage, handling, use, disposal, gathering, movement and remediation of natural gas, NGLs, oil and other hazardous materials; the emission and discharge of such materials to the ground, air and water; wildlife protection; the storage, use and treatment of water; the placement, operation and reclamation of wells; and the health and safety of our employees. Failure to comply with these environmental requirements may result in our being subject to litigation, fines or other sanctions, including the revocation of permits and suspension of operations. We expect to continue to incur significant capital and other compliance costs related to such requirements.

We could be liable for any environmental contamination at our or our predecessors' currently or formerly owned or operated properties or third party waste disposal sites. Certain environmental laws, including CERLA, more commonly know as Superfund, impose joint and several strict liability for releases of hazardous substances at such properties or sites, without regard to fault or the legality of the original contract. In addition to potentially significant investigation and remediation costs, such matters can give rise to claims from governmental authorities and other third parties for fines or penalties, natural resource damages, personal injury and property damage. State regulators in Texas are also becoming increasingly focused on air emissions from our industry, including volatile organic compound emissions. This increased scrutiny could lead to heightened enforcement of existing regulations as well as the imposition of new measures to control our emissions or curtail our operations.

These laws, regulations and permits, and the enforcement and interpretation thereof, change frequently and generally have become more stringent over time. In particular, requirements pertaining to air emissions, including volatile organic compound emissions, have been implemented or are under development that could lead us to incur significant costs or obligations or curtail our operations. For example, GHG emission regulation is becoming more stringent. We are currently required to report annual GHG emissions from some of our operations, and additional GHG emission related requirements are in various stages of development. The U.S. Congress is considering legislation that would establish a nationwide cap-and-trade system for GHGs. In addition, the EPA has proposed regulating GHG emissions from stationary sources pursuant to the Prevention of Significant Deterioration and Title V provisions of the federal Clean Air Act. If enacted, such regulations could require us to modify existing or obtain new permits, implement additional pollution control technology, curtail operations or increase significantly our operating costs. Any regulation of GHG emissions, including through a cap-and-trade system, technology mandate, emissions tax, reporting requirement or other program, could adversely affect our business, financial condition, reputation, operating performance and product demand. In addition, to the extent climate change results in warmer temperatures or more severe weather, our or our customers' operations may be disrupted, which could curtail our exploration and production activity, increase operating costs and reduce product demand. In addition, various U.S. federal and state initiatives are underway to potentially regulate or further investigate the environmental impacts of hydraulic fracturing, a practice that involves the pressurized injection of water, chemicals and other substances into rock formations to stimulate hydrocarbon production. Such initiatives could require the public disclosure of chemicals used in the fracturing process, which disclosure may result in increased scrutiny or third party claims, or otherwise result in operational delays, liabilities and increased costs.

Our costs, liabilities and obligations relating to environmental matters could have a material adverse effect on our business, reputation, 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.

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 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 debt, to otherwise 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.

The provisions of our debt agreements and the risks associated with our debt could adversely affect our business, financial condition and results of operations.

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, require the maintenance of financial covenants that are more fully described in Note 13 to our consolidated financial statements found in Item 8 of this Annual Report. Our ability to comply with the 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 to declare the outstanding principal and 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, we may have insufficient assets 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 December 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 December 31, 2009. 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 December 31, 2009, the holders' election to convert such debentures could result in an aggregate of 9.8 million shares of our common stock being issued. We also had options outstanding to purchase approximately 3.0 million shares of our common stock at December 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.

If we do not make acquisitions on economically acceptable terms, our future growth will be limited.

In addition to expanding production from our current reserves, we may pursue acquisitions. If we are unable to make these acquisitions because we are: (1) unable to identify attractive acquisition candidates, to analyze acquisition opportunities successfully from an operational and financial point of view or to negotiate acceptable purchase contracts with them; (2) unable to obtain financing for these acquisitions on economically acceptable terms; or (3) outbid by competitors, then our future growth could be limited. Furthermore, even if we do make acquisitions, these acquisitions may not result in an increase in the cash generated by operations.

Any acquisition involves potential risks, including, among other things:

- mistaken assumptions about volumes, revenue and costs, including synergies;
- an inability to integrate successfully the assets we acquire;
- the assumption of unknown liabilities;

- limitations on rights to indemnity from the seller;
- mistaken assumptions about the overall costs of equity or debt;
- the diversion of management's and employees' attention from other business matters;
- unforeseen difficulties operating in new product areas, with new customers, or new geographic areas; and
- customer or key employee losses at the acquired businesses.

ITEM 1B. Unresolved Staff Comments

None.

ITEM 2. Properties

A detailed description of our significant properties and associated 2009 developments can be found in Item 1 of this Annual Report, which is incorporated herein by reference.

ITEM 3. Legal Proceedings

Information required with respect to this item is set forth in Note 16 to the consolidated financial statements included in Item 8 of this Annual Report, which is incorporated herein by reference.

ITEM 4. Reserved

PART II.

ITEM 5. Market For Registrant's Common Equity, Related Stockholder Matters and Issuer Purchase of Equity Securities

Market Information

Our common stock is traded on the New York Stock Exchange under the symbol "KWK."

The following table sets forth the quarterly high and low sales prices of our common stock for the periods indicated below.

	HIGH	LOW
2009		
Fourth Quarter	$ 16.55	$ 11.78
Third Quarter	15.10	7.93
Second Quarter	13.35	5.29
First Quarter	8.89	3.98
2008		
Fourth Quarter	$ 20.74	$ 3.74
Third Quarter	40.70	17.13
Second Quarter	44.98	34.96
First Quarter (1)	38.72	24.28

(1) Per share amounts previously reported have been adjusted to reflect a two-for-one stock split effected in the form of a stock dividend in January 2008.

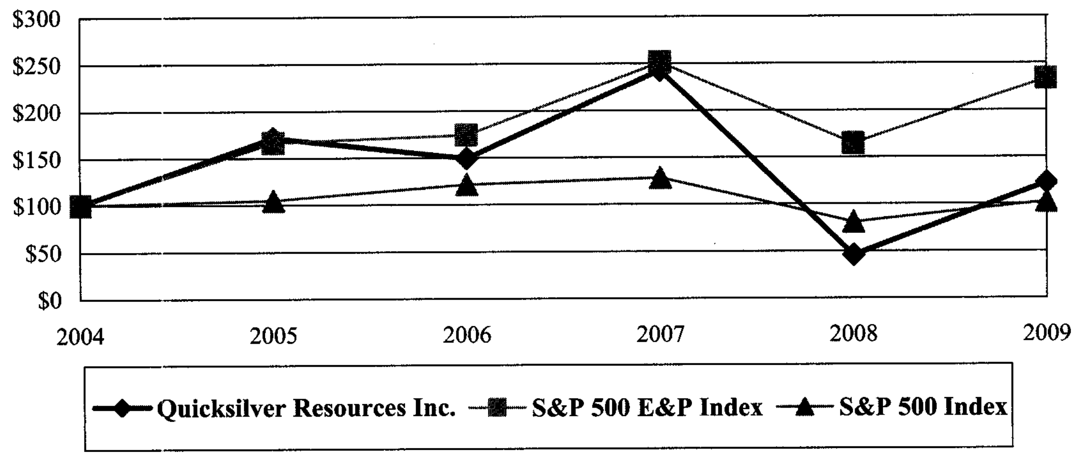
As of February 15, 2010, there were approximately 799 common stockholders of record.

We have not paid cash dividends on our common stock and intend to retain our cash flow from operations for the future operation and development of our business. In addition, we have debt agreements that restrict payments of dividends.

Performance Graph

The following performance graph compares the cumulative total stockholder return on Quicksilver common stock with the Standard & Poor's 500 Stock Index (the "S&P 500 Index") and the Standard & Poor's 500 Exploration and Production Index (the "S&P 500 E&P Index") for the period from December 31, 2004 to December 31, 2009, assuming an initial investment of $100 and the reinvestment of all dividends, if any.

Comparison of Cumulative Five Year Total Return



Issuer Purchases of Equity Securities

The following table summarizes our repurchases of Quicksilver common stock during the quarter ended December 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)]
October 2009	2,197	$ 13.38	-	-
November 2009	1,323	$ 13.27	-	-
December 2009	573	$ 12.46	-	-
Total	4,093	$ 13.22	-	-

(1) Represents shares of common stock surrendered by employees to satisfy the income tax withholding obligations arising upon the vesting of restricted stock issued under our stock plans.

(2) We do not have a publicly announced plan for repurchasing our common stock.

ITEM 6. Selected Financial Data

The following table sets forth, as of the dates and for the periods indicated, our selected financial information and is derived from our audited consolidated financial statements for such periods. The information should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements and notes thereto contained in this Annual Report. The following information is not necessarily indicative of our future results:

	Years Ended December 31,				
	2009 (2)	2008 (3)	2007 (4)	2006	2005
	(In thousands, except for per share data and ratios)				
Operating Results Information					
Total revenues	$ 832,735	$ 800,641	$ 561,258	$ 390,362	$ 310,448
Operating income (loss)	(613,873)	(249,697)	803,581	174,196	149,129
Income (loss) before income taxes	(836,856)	(585,077)	730,806	126,248	122,658
Net income (loss)	(545,239)	(373,622)	476,445	90,097	83,979
Net income (loss) attributable to Quicksilver	(557,473)	(378,276)	475,390	90,006	83,979
Diluted earnings (loss) per common share(1)	$ (3.30)	$ (2.33)	$ 2.87	$ 0.58	$ 0.54
Dividends paid per share	-	-	-	-	-
Cash provided by operating activities	$ 612,240	$ 456,566	$ 319,104	$ 242,186	$ 140,242
Capital expenditures	693,838	1,286,715	1,020,684	619,061	331,805
Financial Condition Information					
Property, plant and equipment - net	$ 3,085,940	$ 3,797,715	$ 2,142,346	$ 1,679,280	$ 1,112,002
Total assets	3,612,882	4,498,208	2,773,751	1,881,052	1,241,437
Long-term debt	2,427,523	2,586,045	788,518	887,917	469,330
All other long-term obligations	121,877	282,101	434,190	191,627	153,518
Total equity	696,822	1,211,563	1,192,468	602,119	406,399

(1) Per share amounts have been adjusted to reflect a three-for-two stock split effected in the form of a stock dividend in June 2005 and a two-for-one stock split effected in the form of a stock dividend in January 2008.

(2) Operating loss for 2009 includes pre-tax charges of $786.9 million and $192.7 million for impairments associated with our U.S. and Canadian oil and gas properties, respectively. Net loss also includes $75.4 million of pre-tax income attributable to our proportionate ownership of BBEP and a pre-tax charge of $102.1 million for impairment of that investment.

(3) Operating loss for 2008 includes a pre-tax charge of $633.5 million for impairment associated with our U.S. oil and gas properties. Net loss also includes $93.3 million for pre-tax income attributable to our proportionate ownership of BBEP and a pre-tax charge of $320.4 million for impairment of that investment.

(4) Operating income and net income for 2007 include a pre-tax gain of $628.7 million recognized from the divestiture of our Northeast Operations and a pre-tax charge of $63.5 million associated with the Michigan Sales Contract (See Note 2 to the consolidated financial statements in Item 8 of this Annual Report).

ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following Management's Discussion and Analysis ("MD&A") is intended to help readers of our financial statements understand our business, results of operations, financial condition, liquidity and capital resources. MD&A is provided as a supplement to, and should be read in conjunction with, the other sections of this Annual Report. We conduct our operations in two segments: (1) our more dominant exploration and production segment, and (2) our significantly smaller gathering and processing segment. Except as otherwise specifically noted, or as the context requires otherwise, and except to the extent that differences between these segments or our geographic segments are material to an understanding of our business taken as a whole, we present this MD&A on a consolidated basis.

Our MD&A includes the following sections:

- *Overview* – a general description of our business; the value drivers of our business; measurements; and opportunities, challenges and risks.
- *Financial Risk Management* – information about debt financing and financial risk management.
- *2009 Highlights* – a summary of significant activities and events affecting Quicksilver.
- *Results of Operations* – an analysis of our consolidated results of operations for the three years presented in our financial statements.
- *Liquidity, Capital Resources and Financial Position* – an analysis of our cash flows, sources and uses of cash, contractual obligations and commercial commitments.
- *Critical Accounting Estimates* – a discussion of critical accounting estimates that represent choices between acceptable alternatives and/or require management judgments and assumptions.

OVERVIEW

We are a Fort Worth, Texas-based independent oil and gas company engaged in the acquisition, exploration, exploitation, development and production of natural gas, NGLs, and oil. We focus primarily on unconventional reservoirs where hydrocarbons may be found in challenging geological conditions such as fractured shales, coal beds and tight sands. We generate revenue, income and cash flows by producing and selling natural gas, NGLs and oil. We conduct acquisition, exploration, exploitation, development and production activities to replace the reserves that we produce.

At December 31, 2009 approximately 99% of our proved reserves were natural gas and NGLs. Consistent with one of our business strategies, we continue to develop and apply our unconventional resources expertise to our development projects in Alberta, Canada and in the Barnett Shale in Texas. Our Texas and Alberta reserves made up 89% and 10%, respectively, of our proved reserves at December 31, 2009. Our acreage in the Horn River Basin in British Columbia will provide additional opportunity for further application of this expertise.

For 2010, we plan to continue our focus on the development and exploitation of our properties in Texas and Alberta and to fund exploration in the Horn River Basin and Green River Basin. We have allocated $390 million of our 2010 consolidated capital program of $540 million for drilling and completion activities. Of the remaining 2010 consolidated capital program, $92 million has been allocated for gathering and processing activities (including approximately $80 million to be funded by KGS), $53 million related to acquisition of additional leasehold interests and $5 million for other property and equipment. Approximately $465 million is allocated to projects in Texas and approximately $52 million is allocated to our Canadian projects (including $17 million in Alberta). The remaining $23 million of the 2010 capital program has been allocated to other areas in the U.S. Our exploratory activities in the Horn River and Green River Basins are expected to consume $58 million of our 2010 capital program.

We focus on three key value drivers:

- reserve growth;
- production growth; and
- maximizing our operating cash flows.

Our reserve growth relies on our ability to apply our technical and operational expertise in our core operating areas to develop, exploit and explore unconventional natural gas reservoirs. We strive to increase reserves and production through aggressive management of operations and through relatively low-risk development and exploitation drilling. We will also continue to identify high-potential exploratory projects with comparatively higher levels of financial risk. All of our development and exploratory programs are aimed at providing us with opportunities to develop and exploit unconventional natural gas reservoirs which align to our technical and operational expertise.

Our core operating areas and the acreage that we hold are well suited for production increases through development and exploitation drilling. We perform workover and infrastructure projects to reduce ongoing operating costs and increase current and future production rates. We regularly review the properties we operate to determine if steps can be taken to efficiently increase reserves and production.

In evaluating the result of our efforts, we consider the capital efficiency of our drilling program and also measure the following key indicators: organic reserve growth; production volumes; cash flow from operating activities; and earnings per share.

	Years Ended December 31,		
	2009	2008	2007
Organic reserve growth [1]	23%	29%	59%
Production volumes (Bcfe)	118.5	96.2	77.9
Cash flow from operating activities (in millions)	$ 612.2	$ 456.6	$ 319.1
Diluted earnings (loss) per share [2][3][4]	$ (3.30)	$ (2.33)	$ 2.87

(1) This ratio is calculated by subtracting adjusted beginning of the year proved reserves from adjusted end of the year proved reserves and dividing by adjusted beginning of the year proved reserves. Adjusted beginning of the year reserves are calculated by deducting divested reserves and adjusted current year production from beginning of the year reserves. Adjusted current year production excludes production from purchased reserves. Adjusted end of the year reserves are calculated by deducting purchased reserves from end of the year reserves.

(2) Diluted earnings for 2009 include pre-tax charges of $786.9 million and $192.7 million for impairments associated with our U.S. and Canadian oil and gas properties, respectively. Net loss also includes $75.4 million of pre-tax income attributable to our proportionate ownership of BBEP and a pre-tax charge of $102.1 million for impairment of that investment.

(3) Diluted earnings for 2008 include a pre-tax charge of $633.5 million for impairment associated with our U.S. oil and gas properties. Net loss also includes $93.3 million of pre-tax income attributable to our proportionate ownership of BBEP and a pre-tax charge of $320.4 million for impairment of that investment.

(4) Diluted earnings for 2007 include a pre-tax gain of $628.7 million recognized from the divestiture of our Northeast Operations and a pre-tax charge of $63.5 million associated with the Michigan Sales Contract.

FINANCIAL RISK MANAGEMENT

We have established internal control policies and procedures for managing risk within our organization. The possibility of decreasing prices received for our natural gas, NGL and oil production is among the several risks that we face. We seek to manage this risk by entering into derivative contracts which we strive to treat as financial hedges. We have mitigated the downside risk of adverse price movements through the use of derivatives but, in doing so, have also limited our ability to benefit from favorable price movements. This commodity price strategy enhances our ability to execute our development, exploitation and exploration programs, meet debt service requirements and pursue acquisition opportunities even in periods of price volatility or depression. Item 7A of this Annual Report contains details of our commodity price and interest rate risk management.

2009 HIGHLIGHTS

Eni Transaction

On June 19, 2009, we completed the Eni Transaction whereby we entered into a strategic alliance with Eni and sold a 27.5% interest in our Alliance Leasehold. The total proceeds for the Eni Transaction were $280 million in cash, inclusive of the Gas Purchase Commitment, subject to normal post-closing adjustments. We used the proceeds from the transaction to repay a portion of the Senior Secured Second Lien Facility. See Note 3 to our consolidated financial statements in Item 8 of this Annual Report.

Long-Term Debt

Upon completion of the Eni Transaction, the borrowing base under the Senior Secured Credit Facility was adjusted to $1.125 billion. Subsequently, a redetermination in October 2009 resulted in a revised borrowing base of $1.0 billion. The Senior Secured Credit Facility provides us an option to increase the commitments by up to $250 million, with a maximum of $1.45 billion with lender consent and additional commitments. We can also extend the facility, which matures on February 9, 2012, up to two additional years with lenders' approval and commitments.

On June 25, 2009, we issued Senior Notes due 2016 with a principal amount of $600 million for proceeds of $580.3 million. The notes bear interest at the rate of 11.75%. The proceeds of these notes, in addition to proceeds from the Eni Transaction, were used to repay and terminate the remaining indebtedness under our Senior Secured Second Lien Facility and to make repayments under the Senior Secured Credit Facility.

On August 14, 2009, we issued Senior Notes due 2019 with a principal amount of $300 million for proceeds of $292.8 million. The notes bear interest at the rate of 9.125%. The proceeds of these notes were used to make repayments under the Senior Secured Credit Facility.

Additional information about our long-term debt is found in Note 13 to our consolidated financial statements in Item 8 of this Annual Report.

KGS Secondary Offering

KGS issued 4,000,000 common units on December 16, 2009 in the KGS Secondary Offering and received $80.3 million, net of underwriters' discount and other offering costs. On January 4, 2010, the underwriters exercised their option to purchase an additional 549,200 common units for $11.1 million, which further reduced our ownership of KGS to 61.2% effective January 6, 2010. The proceeds were used by KGS to repay borrowings of $11 million outstanding under the KGS Credit Agreement in January 2010. KGS also re-borrowed $95 million in January under the KGS Credit Agreement to fund KGS' purchase of the Alliance Midstream Assets. Upon completion of the Alliance Midstream Asset sale to KGS in January 2010, we repaid $95 million of borrowings under the Senior Secured Credit Facility.

Increase in Production

Daily production increased 23% during 2009 from 2008. The production increase is discussed further in *Results of Operations* below.

Horn River Basin Discovery

During 2009, we spent $62 million for exploration and infrastructure development in the Horn River Basin where we have drilled and cased two wells, one of which was placed into service in the third quarter with the second well placed into service in the fourth quarter. Our capital expenditures include costs related to infrastructure development, such as construction of roads and production laterals.

We also entered into a nine-year agreement with a third party that began in May 2009 for the firm processing and transportation of natural gas out of the Horn River Basin with initial volumes of 3 MMcfd and increasing to 100 MMcfd by May 2013.

Litigation Update

In October 2009, a jury awarded $22 million to the plaintiffs in our litigation originally brought against us by the plaintiffs Rod and Richard Thornton and Eagle Drilling, LLC. We are actively seeking an appeal in this matter.

In June 2009, the appellate court in the CMS litigation reversed the original district court judgment. Pursuant to a settlement agreement, we paid CMS $5 million during July 2009, which we accrued during the quarter ended June 30, 2009.

BBEP Update

In February 2009, we received a quarterly distribution of $11.1 million for the quarter ended December 31, 2008. In April 2009, BBEP announced that it was suspending its distributions to remain in compliance with certain provisions of its credit facility and to redirect cash flow to reduce its debt. During the year ended December 31, 2009, we recognized $75.4 million of equity earnings in BBEP and an impairment of $102.1 million.

On February 3, 2010, we entered into a global settlement agreement with BBEP and all other parties to the lawsuit whereby we will receive $18 million in cash along with the retention of full voting rights for our units held in BBEP subject to the provisions of a limited standstill agreement, the ability to name two directors to BBEP's general partner's board of directors, the reinstitution of the BBEP quarterly distributions and other governance accommodations.

RESULTS OF OPERATIONS

Revenue

Natural Gas, NGL and Oil

Production Revenue:

	Natural Gas			NGL			Oil			Total		
	2009	2008	2007	2009	2008	2007	2009	2008	2007	2009	2008	2007
					(In millions)							
Texas	$ 236.6	$ 371.1	$ 121.6	$ 135.5	$ 198.1	$ 106.7	$ 14.0	$ 30.4	$ 9.2	$ 386.1	$ 599.6	$ 237.5
Northeast Operations	-	-	100.8	-	-	4.5	-	-	18.6	-	-	123.9
Other U.S.	0.5	0.8	0.3	0.3	0.8	0.6	8.0	14.8	10.2	8.8	16.4	11.1
Hedging	213.1	(2.4)	26.3	-	(8.6)	(5.2)	-	(7.1)	(0.7)	213.1	(18.1)	20.4
Total U.S.	450.2	369.5	249.0	135.8	190.3	106.6	22.0	38.1	37.3	608.0	597.9	392.9
Canada	90.5	182.7	126.4	0.1	0.4	0.2	0.1	-	-	90.7	183.1	126.6
Hedging	98.0	(0.2)	25.6	-	-	-	-	-	-	98.0	(0.2)	25.6
Total Canada	188.5	182.5	152.0	0.1	0.4	0.2	0.1	-	-	188.7	182.9	152.2
Total	$ 638.7	$ 552.0	$ 401.0	$ 135.9	$ 190.7	$ 106.8	$ 22.1	$ 38.1	$37.3	$ 796.7	$ 780.8	$ 545.1

Average Daily Production Volumes:

	Natural Gas			NGL			Oil			Equivalent Total		
	2009	2008	2007	2009	2008	2007	2009	2008	2007	2009	2008	2007
		(MMcfd)			(Bbld)			(Bbld)			(MMcfed)	
Texas	168.3	122.8	50.1	13,598	11,425	6,395	729	873	349	254.2	196.6	90.6
Northeast Operations	-	-	56.1	-	-	331	-	-	799	-	-	62.9
Other U.S.	0.6	0.3	0.3	34	36	29	434	447	452	3.4	3.2	3.2
Total U.S.	168.9	123.1	106.5	13,632	11,461	6,755	1,163	1,320	1,600	257.6	199.8	156.7
Canada	66.9	63.0	56.8	5	3	13	2	-	-	66.9	63.0	56.9
Total	235.8	186.1	163.3	13,637	11,464	6,768	1,165	1,320	1,600	324.5	262.8	213.6

Average Realized Prices:

	Natural Gas			NGL			Oil			Equivalent Total		
	2009	2008	2007	2009	2008	2007	2009	2008	2007	2009	2008	2007
		(per Mcf)			(per Bbl)			(per Bbl)			(per Mcfe)	
Texas	$ 3.85	$ 8.26	$ 6.65	$ 27.31	$ 47.38	$ 45.70	$ 52.62	$ 95.16	$ 72.37	$ 4.16	$ 8.33	$ 7.18
Northeast Operations	-	-	4.92	-	-	37.36	-	-	63.81	-	-	5.40
Other U.S.	3.62	7.43	4.68	27.02	70.52	52.35	50.53	89.41	61.49	7.41	13.92	9.63
Hedging	3.45	(0.05)	0.81	-	(2.06)	(2.10)	-	(14.72)	(1.19)	2.26	(0.25)	0.45
Total U.S.	$ 7.31	$ 8.20	$ 6.40	$ 27.30	$ 45.39	$ 43.22	$ 51.84	$ 78.83	$ 63.87	$ 6.47	$ 8.18	$ 6.87
Canada	3.71	7.92	6.10	54.66	325.52	48.02	54.80	-	-	3.71	7.94	6.10
Hedging	4.01	(0.01)	1.23	-	-	-	-	-	-	4.01	(0.01)	1.23
Total Canada	$ 7.72	$ 7.91	$ 7.33	$ 54.66	$325.52	$ 48.02	$ 54.80	$ -	$ -	$ 7.72	$ 7.93	$ 7.33
Total	$ 7.42	$ 8.10	$ 6.73	$ 27.32	$ 45.44	$ 43.23	$ 51.85	$ 78.83	$ 63.87	$ 6.73	$ 8.12	$ 6.99

The following table summarizes the changes in our natural gas, NGL and oil revenue:

	Natural Gas	NGL	Oil	Total
		(In thousands)		
Revenue for 2007	$ 400,989	$ 106,787	$ 37,313	$ 545,089
Volume variances	57,227	74,591	(6,463)	125,355
Hedge settlement variances	(59,632)	(3,475)	(6,422)	(69,529)
Price variances	153,462	12,763	13,648	179,873
Revenue for 2008	$ 552,046	$ 190,666	$ 38,076	$ 780,788
Volume variances	145,141	35,484	(4,544)	176,081
Hedge settlement variances	313,493	8,648	7,117	329,258
Price variances	(371,975)	(98,858)	(18,596)	(489,429)
Revenue for 2009	$ 638,705	$ 135,940	$ 22,053	$ 796,698

Our natural gas revenue for 2009 increased from 2008 as a result of increases in production partially offset by a decrease in realized prices. Decreased market prices for natural gas in 2009 reduced revenue $372.0 million, but this reduction was largely offset by a $313.5 million increase from hedge settlements. The increase in U.S. natural gas volumes is due to wells placed into service principally in Texas during 2009. These increases were partially offset by lower volumes resulting from the sale of a 27.5% revenue interest in our Alliance properties in June and natural production declines from existing Texas wells. Canadian natural gas production increased due in part to the Horn River Basin wells placed into service during the third and fourth quarters of 2009.

NGL revenue for 2009 decreased primarily due to lower realized NGL prices for 2009 as compared to 2008. Realized NGL prices decreased despite the absence of $8.6 million paid for hedge settlements in 2008. Partially offsetting the price decrease were increases in production. Texas production increased 19% due to wells placed into production during 2009, lower field pressures and improved NGL recoveries from the Corvette Plant, which was placed into service by KGS during the first quarter of 2009.

Oil revenue for 2009 was lower than 2008 due to decreases in market prices and oil production for 2009 as compared to 2008. An increase in oil and condensate revenue from the absence of outlays for hedge settlements partially offset these decreases.

Natural gas for 2008 increased as a result of both an increase in realized prices and an increase in volumes as compared to 2007. Natural gas prices for 2008 increased significantly compared to 2007 and resulted in additional revenue of $153.5 million that was partially offset by a $59.6 million reduction in 2008 revenue because of the absence of hedge settlements during 2008. Natural gas production in the U.S. increased as a result of the impact of wells placed into production partially offset by production declines for existing Texas wells. The November 2007 divestiture of our Northeast Operations reduced our natural gas production while the Alliance Acquisition increased production by 17.0 MMcfd.

NGL revenue for 2008 increased as a result of production increases and higher realized prices. Additional Texas natural gas production in the high-BTU area of the Barnett Shale and processing improvements during 2008 increased NGL volumes when compared to 2007. Realized prices included higher NGL market prices partially offset by lower revenue because of additional payments for hedge settlements. Partially offsetting the Texas production and pricing increases was the absence of production from the divested Northeast Operations.

Oil revenue for 2008 was higher than 2007 due to an increase in realized prices. Realized prices for oil increased in 2008 despite a reduction in revenue from hedge settlements. Production increases from Texas wells in 2008 partially offset the absence of production from divested Northeast Operations.

Sales of Purchased Natural Gas and Costs of Purchased Natural Gas

	Years Ended December 31,		
	2009	2008	2007
		(in thousands)	
Sales of purchased natural gas:			
Purchases from Eni	$ 11,195	$ -	$ -
Purchases from others	12,459	-	-
Total	23,654	-	-
Costs of purchased natural gas sold:			
Purchases from Eni	12,268	-	-
Purchases from others	11,265	-	-
Unrealized valuation loss on Gas Purchase Commitment	6,625	-	-
Total	30,158		
Net sales and purchases of natural gas	$ (6,504)	$ -	$ -

Our activities related to the purchase and sale of natural gas in Texas are the result of natural gas sales and purchases transacted under the Gas Purchase Commitment. Due to the nature of the Gas Purchase Commitment, we have recognized, and will continue to recognize, unrealized gains and losses associated with our future commitment. The Gas Purchase Commitment is more fully described in Notes 3 and 6 to the consolidated financial statements in Item 8 of this Annual Report.

Other Revenue

Other revenue, consisting primarily of revenue from the processing, gathering and marketing of natural gas and income attributable to hedge derivative ineffectiveness, was $12.4 million for 2009, which was $7.5 million lower than for 2008. KGS' third-party revenue for the 2009 period was $5.4 million less for 2009 when compared to 2008. Additionally, gains attributable to partial ineffectiveness of derivatives hedging our Canadian production were $1.8 million less for 2009 when compared to 2008.

Other revenue was $19.9 million for 2008, an increase of $3.7 million compared with 2007. Throughput from third parties utilizing gathering and processing assets primarily operated by KGS increased other revenue by $6.2 million. Partially offsetting the increase was the absence of $4.3 million of Canadian government grants for new drilling techniques we received in 2007.

Operating Expenses

Oil and Gas Production Expense

	Years Ended December 31,					
	2009		2008		2007	
	(In thousands, except per unit amounts)					
		Per Mcfe		Per Mcfe		Per Mcfe
Texas						
Cash expense	$ 84,216	$ 0.91	$ 90,737	$ 1.26	$ 52,998	$ 1.60
Equity compensation	761	0.01	1,130	0.02	339	0.01
	$ 84,977	$ 0.92	$ 91,867	$ 1.28	$ 53,337	$ 1.61
Northeast Operations						
Cash expense	$ -	$ -	$ -	$ -	$ 48,489	$ 2.11
Equity compensation	-	-	-	-	422	0.02
	$ -	$ -	$ -	$ -	$ 48,911	$ 2.13
Other U.S.						
Cash expense	$ 6,359	$ 5.21	$ 6,318	$ 5.35	$ 3,278	$ 2.97
Equity compensation	195	0.16	190	0.16	193	0.16
	$ 6,554	$ 5.37	$ 6,508	$ 5.51	$ 3,471	$ 3.13
Total U.S.						
Cash expense	$ 90,575	$ 0.95	$ 97,055	$ 1.32	$104,765	$ 1.83
Equity compensation	956	0.02	1,320	0.02	954	0.02
	$ 91,531	$ 0.97	$ 98,375	$ 1.34	$105,719	$ 1.85
Canada						
Cash expense	$ 34,070	$ 1.39	$ 33,781	$ 1.47	$ 28,415	$ 1.37
Equity compensation	2,114	0.09	2,146	0.09	1,969	0.09
	$ 36,184	$ 1.48	$ 35,927	$ 1.56	$ 30,384	$ 1.46
Total Company						
Cash expense	$124,645	$ 1.04	$130,836	$ 1.36	$133,180	$ 1.70
Equity compensation	3,070	0.04	3,466	0.04	2,923	0.04
	$127,715	$ 1.08	$134,302	$ 1.40	$136,103	$ 1.74

U.S. production expense was lower for 2009 despite a 29% production increase from 2008, primarily due to cost containment efforts in Texas during 2009. Texas production expense per Mcfe for 2009 decreased from 2008 as a result of lower saltwater disposal costs, price reductions, and our stringent efforts to contain costs through vendor bidding processes, bulk purchasing and additional reliance on automation of well operations.

Canadian production expense for 2009 was unchanged from 2008. Canadian production expense per Mcfe for 2009 decreased because of production increases. Production expense on a Canadian dollar basis for 2009 compared to 2008 increased approximately C$3.3 million or 9% due primarily to the Canadian production increase.

Oil and gas production expense for 2008 decreased slightly from 2007. The absence of production expense from the divested Northeast Operations was almost entirely offset by the growth of our operations in Texas and Canada that increased production expense in those areas as production volumes increased 117% and 11%, respectively, for 2008 as compared to 2007, as discussed previously.

Although oil and gas production expense for our Texas operations was higher for 2008, production expense per Mcfe decreased 20% when compared to 2007. The improvement in production expense on a Mcfe-basis was primarily the result of higher production levels, cost containment initiatives, new completion techniques used in our capital program and higher utilization of automation during 2008. Canadian production expense increased primarily as a result of the 11% increase in production volumes, an increase in personnel costs and higher prevailing exchange rates during 2008.

Production and Ad Valorem Taxes

	Years Ended December 31,					
	2009		2008		2007	
	(In thousands, except per unit amounts)					
Production and ad valorem taxes		Per Mcfe		Per Mcfe		Per Mcfe
U.S.	$ 21,403	$ 0.23	$ 15,999	$ 0.22	$ 13,912	$ 0.24
Canada	2,478	$ 0.10	2,735	$ 0.12	3,136	$ 0.15
Total	$ 23,881	$ 0.20	$ 18,734	$ 0.19	$ 17,048	$ 0.22

Production and ad valorem taxes for 2009 reflect the addition of wells and midstream facilities in Texas during 2009 although such costs were almost unchanged on a Mcfe-basis.

Production and ad valorem tax expense for 2008 increased $1.7 million as compared to 2007. U.S. ad valorem and production taxes increased $11.8 million due to the development of our Texas properties, increased production and higher pricing. This increase was nearly offset by the absence of $9.5 million for production and ad valorem taxes associated with the divested Northeast Operations.

Other Operating Expense

The $3.3 million increase in other operating expense for 2009 as compared to 2008 was primarily the result of commissioning and other operating expenses associated with the operation of our Alliance Midstream Assets and other Texas midstream operations not owned by KGS.

Depletion, Depreciation and Accretion

	Years Ended December 31,					
	2009		2008		2007	
	(In thousands, except per unit amounts)					
		Per Mcfe		Per Mcfe		Per Mcfe
Depletion						
U.S.	$ 127,888	$ 1.36	$ 120,845	$ 1.65	$ 65,020	$ 1.14
Canada	33,782	1.38	40,337	1.75	34,666	1.67
	161,670	1.36	161,182	1.68	99,686	1.28
Total depletion						
U.S.	$ 33,329	$ 0.35	$ 21,751	$ 0.30	$ 15,389	$ 0.27
Canada	3,952	0.16	3,780	0.16	4,115	0.20
Total depreciation	37,281	0.31	25,531	0.27	19,504	0.25
Accretion	2,436	0.02	1,483	0.01	1,507	0.02
Total	$ 201,387	$ 1.70	$ 188,196	$ 1.96	$120,697	$ 1.55

Depletion for 2009 was relatively unchanged from 2008 as production increases were almost entirely offset by lower depletion rates. Our U.S. depletion expense increased due primarily to the 29% increase in U.S. production volumes. Both our U.S. and Canadian depletion rates were impacted by impairment charges. U.S. impairment charges were recognized in the fourth quarter of 2008 and the first quarter of 2009. Canadian impairment charges were recognized in the first, second and fourth quarters of 2009. Changes in the U.S.-Canadian dollar exchange rate also contributed to lower Canadian depletion expense and the Canadian depletion rate on a Mcfe-basis. We expect that our consolidated depletion rate for 2010 will be in a range of $1.20 to $1.25 per Mcfe.

The change in the exchange rate decreased depletion $2.6 million when comparing 2009 to 2008. The $11.6 million increase in U.S. depreciation for 2009 as compared to 2008 was primarily associated with additions of Fort Worth Basin field compression, Alliance gathering and processing facilities and KGS' gathering system in addition to KGS' Corvette Plant that was placed into service in the first quarter of 2009.

Higher depletion expense for 2008 resulted from a 31% increase in the depletion rate and a 23% increase in production volumes. Our 2008 depletion rate was impacted by the addition of the proved oil and gas properties obtained in the Alliance Acquisition as well as the capital costs incurred for proved reserves added from our existing properties and increases in estimated future capital expenditures. Depreciation expense for 2008 was $10.4 million higher than 2007 primarily due to additions of Fort Worth Basin field compression and KGS midstream infrastructure, partially offset by the absence of $4.1 million of depreciation expense associated with the divested Northeast Operations' depreciable assets.

Impairment of Oil and Gas Properties

As required under GAAP, we perform quarterly ceiling tests to assess impairment of our oil and gas properties. Net capitalized costs include the book value of our oil and gas properties net of accumulated depletion and impairment, reduced by the related asset retirement obligations and deferred tax liabilities. Net capitalized costs are compared to the period end ceiling limitation, which is the sum of:

- estimated future net cash flows, discounted at 10% per annum, from proved reserves, based on an unweighted average of preceding 12-month first-day-of-the-month prices for the year then ended (year-end prices for 2008 and 2007) adjusted to reflect local differentials, unescalated period end costs and expenses, adjusted for financial derivatives that qualify as cash flow hedges of our oil and gas revenue,
- the costs of properties not being amortized,
- the lower of cost or market value of unproved properties not included in the costs being amortized, less
- income tax effects related to differences between book and tax bases of the oil and gas properties.

We recognized noncash pre-tax charges totaling $979.6 million ($656.0 million after tax) for impairments related to both our U.S. and Canadian oil and gas properties in 2009. The primary factor that caused the decrease in the estimated future cash flows from our proved oil and gas reserves was lower benchmark natural gas prices at March 31, 2009 for the U.S. and Canada and further Canadian price decreases at June 30, 2009. Additionally, reductions in the expected Canadian capital investment for the following 12- and 18-month periods at June 30, 2009 further decreased estimated Canadian future net cash flows from our proved oil and gas reserves. At September 30, 2009, the unamortized cost of our Canadian oil and gas properties exceeded the full cost ceiling limitation by approximately $38.8 million (pre-tax). As permitted by full cost accounting rules in effect at that date, improvements in AECO spot natural gas prices subsequent to September 30, 2009 eliminated the necessity to record a charge for impairment.

Use of the unweighted average of the preceding 12-month first-day-of-the-month prices as required by the SEC effective December 31, 2009, resulted in a fourth quarter impairment of our Canadian oil and gas properties. Note 10 to the consolidated financial statements in Item 8 of this Annual Report contains additional information about the ceiling test calculation.

We recognized a noncash pre-tax charge of $633.5 million ($411.8 million after tax) for impairment related to our U.S. oil and gas properties in December 2008. The impairment charge was primarily a result of the significantly lower natural gas and NGL prices at year-end 2008 as compared to year-end 2007.

General and Administrative Expense

	Years Ended December 31,					
	2009		2008		2007	
	(In thousands, except per unit amounts)					
General and administrative expense		Per Mcfe		Per Mcfe		Per Mcfe
Cash expense	$ 55,200	$ 0.47	$ 49,982	$ 0.52	$ 38,595	$ 0.50
Litigation resolution	5,000	0.04	9,633	0.10	-	-
Equity compensation	17,043	0.14	12,639	0.13	8,465	0.11
Total	$ 77,243	$ 0.65	$ 72,254	$ 0.75	$ 47,060	$ 0.60

Despite a decrease in litigation resolution costs, 2009 legal fees increased $6.1 million because of our litigation with BBEP, the Eni Transaction and various other corporate matters. Non-cash expense for stock-based compensation in 2009 increased $4.4 million when compared to 2008.

General and administrative expense for 2008 increased $25.2 million, which included a charge of $9.6 million in 2008 as a result of the settlement of litigation as discussed in Note 16 to our consolidated financial statements in Item 8 of this Annual Report. The most significant increase in recurring general and administrative expense for 2008 was a $14.4 million increase in employee compensation and benefits, including increases of $4.2 million of non-cash expense for stock-based compensation and $1.3 million in performance-based compensation. The remaining $8.9 million increase in employee compensation is related to additional headcount hired to bring our infrastructure to a level needed to accommodate growth in our operations and production. After consideration of the BreitBurn Transaction investment banking fees of $2.0 million recognized in 2007, fees for legal, accounting and other professional services increased general and administrative expense by approximately $2.8 million, which resulted from additional regulatory filing requirements, litigation costs, expenses associated with evaluation of complex business transactions and the full year effect of KGS being a publicly-traded partnership.

Other Components of Operating Income

During 2007, we recognized a gain of $628.7 million as a result of our divestiture of the Northeast Operations, and we recorded a loss on the Michigan Sales Contract related to delivery of volumes in Michigan. Further information regarding these transactions is included in Note 5 of our consolidated financial statements found in Item 8 of this Annual Report.

Income from Earnings of BBEP

During 2009, we recognized $75.4 million for equity earnings from our investment in BBEP. We record our portion of BBEP's earnings during the quarter in which their financial statements become publicly available. As a result, our 2009 annual results of operations include BBEP's earnings for the 12 months ended September 30, 2009. Our 2008 results of operations reflect BBEP's earnings from November 1, 2007, when we acquired BBEP units, through September 30, 2008. The increase in equity earnings recognized during 2009 is primarily due to a significant reduction in unrealized losses from derivative instruments that BBEP experienced compared with the prior year 11-month period. BBEP has continued 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.

We recognized $93.3 million of income associated with the equity earnings from our investment in BBEP in 2008 for the period November 1, 2007, when we acquired the BBEP units, through September 30, 2008. This amount reflects our prevailing ownership interests for the applicable period before and after our ownership increased from 32% to 41% by virtue of BBEP's purchase and retirement of units during 2008.

Impairment of Investment in BBEP

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 after December 31, 2008. As a result of these decreases, we made the determination that the decline in value was other-than-temporary.

Accordingly, our impairment analysis, which utilized the March 31, 2009 closing price of $6.53 per BBEP unit, resulted in aggregate fair value of $139.4 million for the portion of BBEP units that we owned. 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. A similar analysis was performed at each subsequent quarter-end of 2009, which resulted in no further impairment. Note 9 to our consolidated financial statements found in Item 8 of this Annual Report contains additional information regarding our investment in BBEP.

During the fourth quarter of 2008, our management considered the fair value of the BBEP units along with the fair value trend of its peers, the trend and future petroleum strip prices and the limited availability of credit which occurred in the latter half of 2008. Based on these factors, management determined that the decrease in fair value of BBEP units was other-than-temporary and recorded a pre-tax charge of $320.4 million to reduce the carrying value of our investment in BBEP to its fair value.

Interest Expense

	Years Ended December 31,		
	2009	2008	2007
		(in thousands)	
Interest costs on debt outstanding	$ 155,696	$ 105,108	$ 67,379
Add:			
Non-cash interest [1]	18,410	13,215	10,374
Non-cash loss on early debt extinguishment	27,122	-	-
Less: Interest capitalized	(6,127)	(9,225)	(1,091)
Interest expense	$ 195,101	$ 109,098	$ 76,662

[1] Amortization of deferred financing costs and original issue discount.

Interest costs for 2009 were higher than 2008 primarily because of higher outstanding debt balances, which included the issuance of our senior notes due 2016 in June 2009 and our senior notes due 2019 in August 2009. The proceeds from the issuance of the Senior Notes due 2016 were used to fully repay the Senior Secured Second Lien Credit Facility in June 2009. At that time, we recognized additional interest expense of $27.1 million for the remaining unamortized original issue discount and deferred financing costs associated with the Senior Secured Second Lien Facility. Interest rate swaps entered into in June 2009 partially offset increases of interest expense by $13.7 million for 2009. We expect interest expense to be in a range of $200 million to $210 million for 2010, based on current market conditions and expected borrowing levels.

Interest expense for 2008 was higher than 2007 primarily because of higher average debt outstanding due to the issuance of our senior notes due 2015 and our Senior Secured Second Lien Facility due in 2013, partially offset by a decrease in our average consolidated interest rate. The higher debt levels in 2008 relate to the Alliance Acquisition and the funding of the 2008 capital program. The increase in capitalized interest related to more projects and costs within those projects being subject to capitalization. Interest was capitalized in 2008 for our exploration projects in the Horn River Basin and West Texas and construction of the Corvette Plant by KGS.

Income Taxes

	Years Ended December 31,		
	2009	2008	2007
		(in thousands)	
Income tax expense (benefit)	$ (291,617)	$ (211,455)	$ 254,361
Effective tax rate	34.8%	36.1%	34.8%

Our income tax provision for 2009 changed from 2008 due to a $251.8 million reduction of pre-tax earnings that resulted primarily from higher aggregate impairment charges for our oil and gas properties recognized during 2009 when compared to 2008. The effective tax rate for 2009 was affected by the resulting taxable net loss in both the U.S. and Canada that were taxed at approximately 35% and approximately 26%, respectively.

The 2008 provision for income taxes changed dramatically from 2007 due to the loss generated by U.S. operations for 2008. Pre-tax results for 2008 compared with 2007 were most significantly influenced by the impairment charges recognized on U.S. oil and gas properties and on our investment in BBEP. Also, 2007 results included the gain resulting from our divestiture of our Northeast Operations. Higher Canadian pre-tax income and the absence of tax credits received in 2007 increased the provision for income taxes in Canada by $11.1 million. In 2008, the effective rate exceeded the statutory rate of 35% due to the benefit of lower taxes in Canada partially offset by impact of permanent differences for executive compensation and meals and entertainment.

Quicksilver Resources Inc. and its Restricted Subsidiaries

Information about Quicksilver and our restricted and unrestricted subsidiaries is included in Note 20 to our consolidated financial statements included in Item 8 in this Annual Report.

The combined results of operations for Quicksilver and our restricted subsidiaries are substantially similar to our consolidated results of operations, which are discussed above under *"Results of Operations"*. The combined financial position of Quicksilver and our restricted subsidiaries and our consolidated financial position are materially the same except for the property, plant and equipment purchased by the unrestricted subsidiaries since the KGS initial public offering, the borrowings under the KGS Credit Agreement and the equity of the unrestricted subsidiaries. The other balance sheet items are discussed below in *"Financial Position"*. The combined operating cash flows, financing cash flows and investing cash flows for Quicksilver and our restricted subsidiaries are substantially similar to our consolidated operating cash flows, financing cash flows and investing cash flows, which are discussed below in "Cash Flow Activity".

LIQUIDITY, CAPITAL RESOURCES AND FINANCIAL POSITION

Cash Flow Activity

Operating Cash Flows

	Years Ended December 31,		
	2009	2008	2007
		(In thousands)	
Net cash provided by operating activities	$ 612,240	$ 456,566	$ 319,104

Cash flows provided by operating activities in 2009 increased because of contributions from working capital including $54.9 million received from the March 2009 early settlement of a derivative hedging 40 MMcfd of 2010 natural gas production and receipt of a $41.1 million U.S. federal income tax refund. Other components of cash flows provided by operations for 2009 decreased despite significantly higher production and lower production expense because of higher interest payments on our outstanding debt and cash losses from monthly settlements of the Gas Purchase Commitment. Additionally, the cash distributions we receive on our BBEP units decreased $31.4 million from 2008 to $11.1 million as BBEP eliminated 2009 quarterly distributions.

Cash flows provided by operating activities in 2008 increased from 2007 primarily due to a 23% production increase and a 16% increase in realized price per Mcfe. Payments of $46.6 million for income taxes and other uses of working capital partially offset the increase in earnings from high production and prices. See additional information regarding operating activities in *"Results of Operations"*.

Investing Cash Flows

	Years Ended December 31,		
	2009	2008	2007
		(In thousands)	
Purchases of property, plant and equipment	$ (693,838)	$ (1,286,715)	$ (1,020,684)
Alliance Acquisition	-	(993,212)	-
Return of investment from equity affiliates	-	-	9,635
Proceeds from sales of properties & equipment	220,974	1,339	741,297
Net cash used by investing activities	$ (472,864)	$ (2,278,588)	$ (269,752)

For each of the three years ended December 31, 2009, we have spent significant cash resources for the development of our large acreage positions in our core areas in Texas and Alberta. In addition, our expenditures for gas processing and gathering assets have grown significantly as part of our growth in Texas. We completed several significant transactions over the three years ended December 31, 2009, including the 2009 Eni Transaction with net cash proceeds of $219.2 million, our 2008 Alliance Acquisition for cash of $1.0 billion and the 2007 divestiture of our Northeast Operations that resulted in cash proceeds of $741.1 million.

We reduced our 2009 exploration and development activity from 2008 levels in response to lower natural gas and NGL prices. Of the $693.8 million of cash paid for property, plant and equipment during 2009, 79% was invested in our oil and natural gas properties and 20% was invested in our gas processing and gathering operations. We drilled 154 (93.2 net) wells in the Fort Worth Basin and 141 (36.1 net) wells in Alberta. Our 2009 midstream capital investment of $123.0 million was primarily related to expansion of our Texas gas processing and gathering facilities.

Our 2008 purchases of property, plant and equipment reflect our expansion in our core operating areas in Texas and Alberta. In 2008, we purchased approximately 90 producing wells in the Alliance Acquisition and drilled 296 (259.7 net) wells in Texas and 373 (156.9 net) wells in Alberta. Additionally, the assets purchased in the Alliance Acquisition included a gathering system and we invested $230.4 million and $4.3 million for Fort Worth Basin and Canadian gas processing and gathering facilities, respectively.

Capital costs incurred for development, exploitation and exploration activities in 2007 were $852.5 million, primarily for expansion in our two core operating areas. In 2007, we drilled 244 (219.4 net) wells in the Fort Worth Basin and an additional 356 (184.1 net) wells in Alberta. Additionally, we invested $168.5 million and $3.4 million for Texas and Canadian gas processing and gathering facilities, respectively.

We currently estimate that our spending for property, plant and equipment in 2010 will be approximately $540 million, of which we have allocated $390 million for drilling and completion activities, including $340 million in Texas, $34 million in Canada and $17 million in other areas in the U.S. We have also budgeted $92 million for gathering and processing facilities (including $80 million to be funded directly by KGS), $53 million for acquisition of additional leasehold interests and $4 million for other property and equipment.

Financing Cash Flows

	Years Ended December 31, 2009	2008	2007
		(In thousands)	
Issuance of debt	$ 1,420,727	$ 2,948,672	$ 817,821
Repayments of debt	(1,649,630)	(1,096,163)	(968,557)
Debt issuance costs	(32,472)	(25,219)	(5,130)
Gas Purchase Commitment	58,294	-	-
Gas Purchase Commitment repayments	(14,175)	-	-
Issuance of KGS common units	80,729	-	109,809
Distributions paid on KGS common units	(9,925)	(8,644)	(8,794)
Proceeds from exercise of stock options	4,046	1,244	21,387
Excess tax benefit on exercise of stock options	-	-	2,755
Purchase of treasury stock	(922)	(23,137)	(1,567)
Net cash provided (used) by financing activities	$ (143,328)	$ 1,796,753	$ (32,276)

Net cash flows from financing activities for 2009 reflect our efforts to restructure and reduce our debt outstanding at December 31, 2008. In 2009, we received total proceeds of $873.1 million from the issuance of our senior notes due 2016 with a principal amount of $600 million and our senior notes due 2019 with a principal amount of $300 million. The senior notes due 2016 bear interest at the rate of 11.75% paid semiannually on January 1 and July 1. The senior notes due 2019 bear interest at the rate of 9.125% paid semiannually on February 15 and August 15. Borrowings and repayments in 2009 under the Senior Secured Credit Facility were $492 million and $890 million, respectively, which resulted in a net decrease of $398 million outstanding in 2009. KGS increased borrowings under the KGS Credit Agreement by $49.5 million in 2009.

Proceeds from the debt issuances and the Eni Transaction were used to repay and terminate the remaining indebtedness under our Senior Secured Second Lien Facility and to repay a portion of the outstanding borrowings under the Senior Secured Credit Facility. The KGS Secondary Offering, completed in December 2009, resulted in net proceeds of $80.3 million for 4,000,000 common units and reduced our ownership interest in KGS from approximately 73% to approximately 62% as of December 31, 2009. In January 2010, the underwriters exercised their option to purchase an additional 549,200 KGS common units for $11.1 million, which further reduced our ownership of KGS to approximately 61%.

Net cash flows from financing activities during 2008 were significantly impacted by the Alliance Acquisition and our 2008 capital program. We funded our capital program in excess of operating cash flow through the issuance of our Senior Notes due 2015 and additional borrowing under our Senior Secured Credit Facility. The Alliance Acquisition was funded by a $700 million five-year Senior Secured Second Lien Facility and additional borrowing under our Senior Secured Credit Facility.

Net cash flows from financing activities during 2007 were significantly impacted by the KGS IPO and the divestiture of our Northeast Operations. The KGS IPO resulted in cash proceeds of $110 million primarily used to repay debt. The divestiture of our Northeast Operations generated net cash proceeds of $741.1 million included in investing activities, however those proceeds were used to pay down debt previously outstanding which was reflected in financing cash flows.

Liquidity and Borrowing Capacity

Our Senior Secured Credit Facility matures on February 9, 2012. The borrowing base at December 31, 2009 was $1.0 billion which was the result of a redetermination in October 2009. The Senior Secured Credit Facility currently provides us an option to increase the commitment by up to $250 million, with a maximum of $1.45 billion with lender consents and additional commitments. We can also extend the facility up to two additional years with lenders' approval. The borrowing base is subject to at least an annual redetermination.

The facility provides for revolving loans, swingline loans and letters of credit from time to time in an aggregate amount not to exceed the borrowing base which is calculated based on several factors. The lenders' commitments under the facility are allocated between U.S. and Canadian funds. U.S. borrowings under the facility are secured by, among other things, Quicksilver's and our U.S. subsidiaries' oil and gas properties. Canadian borrowings under the facility are secured by, among other things, all of our oil and gas properties. We also pledged our equity interests in BBEP to secure our obligations under the Senior Secured Credit Facility. At December 31, 2009, there was approximately $498 million available under the facility. In January 2010, we repaid $95 million of borrowings outstanding under the Senior Secured Credit Facility using the proceeds from the sale of the Alliance Midstream Assets to KGS. Our ability to remain in compliance with the financial covenants in our credit facility may be affected by events beyond our control, including market prices for our products. Any future inability to comply with these covenants, unless waived by the requisite lenders, could adversely affect our liquidity by rendering us unable to borrow further under our credit facilities and by accelerating the maturity of our indebtedness.

The KGS Credit Agreement matures August 10, 2012, but may be extended up to two additional years with lenders' approval. In October 2009, the lenders increased their commitments to a total of $320 million. At December 31, 2009, KGS had approximately $172 million available under the KGS Credit Agreement. The KGS Credit Agreement permits further expansion to as much as $350 million, subject to lender consent and additional commitments. KGS must maintain certain financial ratios that can limit its borrowing capacity. KGS' ability to remain in compliance with the financial covenants in its credit agreement may be affected by events beyond our or KGS' control. Any future inability to comply with these covenants, unless waived by the requisite lenders, could adversely affect our liquidity by rendering KGS unable to borrow further under its credit agreement and by accelerating the maturity of its indebtedness. KGS received $11.1 million from the underwriters' January exercise of their option to purchase an additional 549,200 units and repaid $11 million of borrowings outstanding under the KGS Credit Agreement. KGS also re-borrowed $95 million under the KGS Credit Agreement to fund KGS' purchase of the Alliance Midstream Assets.

Additional information about our debt and related covenants are more fully described in Note 13 to the consolidated financial statements in Item 8 of this Annual Report.

We believe that our capital resources are adequate to meet the requirements of our existing business. We anticipate that our 2010 capital expenditure program of approximately $540 million will be funded by cash flow from operations. We may, from time to time during 2010, make borrowings under the Senior Secured Credit Facility, but expect that for all of 2010 to require no incremental borrowings above 2009 levels. Conversely, we anticipate that KGS may experience increases to its outstanding borrowings to fund further development of its gathering and treating capacity in the Alliance area.

Depending upon conditions in the capital markets and other factors, we will from time to time consider the issuance of debt or other securities, other possible capital markets transactions or the sale of assets, the proceeds of which could be used to refinance current indebtedness or for other corporate purposes. We will also consider from time to time additional acquisitions of, and investments in, assets or businesses that complement our existing asset portfolio. Acquisition transactions, if any, are expected to be financed through cash on hand and from operations, bank borrowings, the issuance of debt or other securities or a combination of those sources.

Financial Position

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

- Our current and non-current derivative assets and liabilities decreased $165.8 million on a net basis. Our net open derivative position decreased $310.9 million because of monthly settlements during 2009 and $54.9 million received for early settlement of a derivative hedging a portion of our 2010 production. The valuation of our open derivative positions at December 31, 2009 partially offset these decreases. Our current deferred income tax liability related to our derivatives was almost unchanged because of changes in the allocation of open derivative positions between the U.S. and Canada and the difference between U.S. and Canadian statutory tax rates.

- Our net property, plant and equipment balance decreased $711.8 million from December 31, 2008 to December 31, 2009. During 2009, we recorded charges for impairment of our oil and gas properties of $979.5 million and 2009 DD&A expense of $199.1 million. Our property, plant and equipment balances were also decreased by proceeds of $219.6 million for the Eni Transaction. These decreases were partially offset by $601.7 million of costs incurred for property, plant and equipment, and an additional $84.7 million for changes to U.S.-Canadian exchange rates and assets recognized when retirement obligations were established for new wells and facilities.
- Our deferred income tax liability has decreased $192.5 million and a U.S. deferred tax asset of $133.1 million was recognized in connection with the impairments of both our investment in BBEP and our U.S. oil and gas properties.
- Equity held by noncontrolling interests increased $34.1 million, which consisted of $30.1 million from the KGS Secondary Offering, employee unit compensation of $1.7 million and income attributable to noncontrolling interests of $12.2 million partially offset by $9.9 million of distributions paid to noncontrolling interests.

Contractual Obligations and Commercial Commitments

Contractual Obligations. Information regarding our contractual and scheduled interest obligations, at December 31, 2009, is set forth in the following table.

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
			(In thousands)		
Long-term debt	$ 2,467,969	$ -	$ 592,969	$ 475,000	$ 1,400,000
Scheduled interest obligations	1,135,247	166,782	494,438	309,705	164,322
Transportation and processing contracts	629,116	43,909	238,382	157,272	189,553
Drilling rig contracts	96,606	45,519	51,087	-	-
Gas Purchase Commitment	50,744	50,744	-	-	-
Purchase obligations	24,827	19,554	5,273	-	-
Asset retirement obligations	59,378	109	195	130	58,944
Unrecognized tax benefits	9,219	-	9,219	-	-
Operating lease obligations	7,928	2,678	4,274	976	-
Total obligations	$ 4,481,034	$ 329,295	$ 1,395,837	$ 943,083	$ 1,812,819

- *Long-Term Debt.* As of December 31, 2009, our outstanding indebtedness included $468 million outstanding under our Senior Secured Credit Facility, $475 million of Senior Notes due 2015, $600 million of Senior Notes due 2016, $300 million of Senior Notes due 2019, $350 million of Senior Subordinated Notes, $150 million of contingently convertible debentures and $125 million outstanding under the KGS Credit Facility (all before original issue discount). Based upon our debt outstanding and interest rates in effect at December 31, 2009, we anticipate interest payments, including our scheduled interest obligations, to be approximately $184.3 million in 2010. Although we do not expect year-over-year increased borrowings under our Senior Secured Credit Facility during 2010, should we be required to increase those borrowings and based on interest rates in effect at December 31, 2009, an additional $50 million in borrowings would result in additional annual interest payments of approximately $1.7 million. If the current borrowing base under our Senior Secured Credit Facility were to be fully utilized by year-end 2010 at interest rates in effect at December 31, 2009, we estimate that annual interest payments would increase by approximately $16.5 million. If interest rates on our December 31, 2009 variable debt balances of approximately $1.4 billion, including $825 million subject to fixed to floating interest rate swaps, increase or decrease by one percentage point, our annual pre-tax income would decrease or increase by $14.2 million.

- *Scheduled Interest Obligations.* As of December 31, 2009, we had scheduled interest payments of $39.2 million annually on our Senior Notes due 2015, $70.5 million annually on our Senior Notes due 2016, $27.4 million annually on our Senior Notes due 2019, $24.9 million annually on our $350 million of Senior Subordinated Notes and $2.8 million annually on our $150 million of contingently convertible debentures. Additional interest of $1.3 million and $0.7 million is payable in 2010 on the Senior Secured Credit Facility and KGS Credit Agreement, respectively.

- *Transportation and Processing Contracts.* Under contracts with various pipeline and processing companies, we are obligated to provide minimum daily natural gas volumes for transport or processing, as calculated on a monthly basis, or pay for any volume deficiencies at a specified reservation fee rate. Our production committed to the pipelines or processing plants is expected to meet, or exceed, the daily volumes provided in the contracts.

- *Drilling Rig Contracts.* We utilize drilling rigs from third parties in our development and exploration programs. The outstanding drilling rig contracts require payment of a specified day rate ranging from $20,500 to $26,500 for the entire lease term regardless of our utilization of the drilling rigs.

- *Gas Purchase Commitment.* Pursuant to the Eni Transaction we agreed to purchase Eni's share of Alliance Leasehold production at $8.60 per MMBtu less costs related to gathering and processing Eni's Alliance Production through December 2010.

- *Purchase Obligations.* At December 31, 2009, we and KGS were under contract to purchase goods and services for use in field and gas plant operations. KGS remaining cash obligations for such items were $7.4 million.

- *Asset Retirement Obligations.* Our obligations result from the acquisition, construction or development and the normal operation of our long-lived assets.

- *Unrecognized Tax Benefits.* We have recorded obligations that have resulted from tax benefit claims in our tax returns that do not meet the recognition standard of more likely than not to be sustained upon examination by tax authorities. The $9.2 million balance of unrecognized tax benefits includes $8.9 million of amounts that, if recognized, would reduce our effective tax rate.

- *Operating Lease Obligations.* We lease office buildings and other property under operating leases.

Commercial Commitments. We had the following commercial commitments as of December 31, 2009:

	Amounts of Commitments by Expiration Period				
	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
			(In thousands)		
Surety bonds	$ 39,069	$ 39,069	$ -	$ -	$ -
Standby letters of credit	34,522	34,522	-	-	-
Total	$ 73,591	$ 73,591	$ -	$ -	$ -

- *Surety Bonds.* Our surety bonds have been issued to fulfill contractual, legal or regulatory requirements. Surety bonds generally have an annual renewal option.

- *Standby Letters of Credit.* Our letters of credit have been issued to fulfill contractual or regulatory requirements, including $21.4 million issued to provide credit support for surety bonds. All of these letters of credit were issued under our Senior Secured Credit Facility and generally have an annual renewal option.

CRITICAL ACCOUNTING ESTIMATES

Our consolidated financial statements are prepared in accordance with GAAP. In connection with the preparation of our financial statements, we are required to make assumptions and estimates about future events, and apply judgments that affect the reported amounts of assets, liabilities, revenue, expenses and the related disclosures. We base our assumptions, estimates and judgments on historical experience, current trends and other factors that management believes to be relevant at the time we prepare our consolidated financial statements. On a regular basis, management reviews the accounting policies, assumptions, estimates and judgments to ensure that our financial statements are presented fairly and in accordance with GAAP. However, because future events and their effects cannot be determined with certainty, actual results could differ materially from our assumptions and estimates.

Our significant accounting policies are discussed in Note 2 to the consolidated financial statements included in Item 8 of this Annual Report. Management believes that the following accounting estimates are the most critical in fully understanding and evaluating our reported financial results, and they require management's most difficult, subjective or complex judgments, resulting from the need to make estimates about the effect of matters that are inherently uncertain. Management has reviewed these critical accounting estimates and related disclosures with our Audit Committee.

Oil and Gas Reserves

Policy Description

Proved oil and gas reserves are the estimated quantities of oil, natural gas, and NGLs that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. In December 2008, the SEC adopted its final rule for "Modernization of Oil and Gas Reporting." The most significant changes incorporated into our proved reserve process and related disclosures for 2009 include:

- the use of an unweighted average of the preceding 12-month first-day-of-the-month prices for determination of proved reserve values included in calculating full cost ceiling limitations and for annual proved reserve disclosures;
- consideration of and limitations on the types of technologies that may be used to reliably establish and estimate proved reserves;
- reporting of investments and progress made during the year to convert proved undeveloped reserves to proved developed reserves; and,
- reporting on the independence and qualifications of our personnel and independent petroleum engineers who are responsible for the preparation of our reserve estimates.

Operating costs are the period end operating cost at the time of the reserve estimate and held constant. Our estimates of proved reserves are made and reassessed at least annually using available geological and reservoir data as well as production performance data. Revisions may result from changes in, among other things, reservoir performance, prices, economic conditions and governmental restrictions. Our proved reserve estimates and related disclosures for 2009 are presented in compliance with this new guidance. Our 2008 and 2007 proved reserve estimates and related disclosures were prepared in compliance with the SEC guidance then in effect. Additional information regarding our estimated proved oil and gas reserves may be found under "Oil and Natural Gas Reserves" found in Item 1 of this Annual Report.

Judgments and Assumptions

All of the reserve data in this Annual Report are based on estimates. Estimates of our oil, natural gas and NGL reserves are prepared in accordance with guidelines established by the SEC. Reservoir engineering is a subjective process of estimating recoverable underground accumulations of oil, natural gas and NGLs. There are numerous uncertainties inherent in estimating recoverable quantities of proved oil and natural gas reserves. Uncertainties include the projection of future production rates and the expected timing of development expenditures. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserve estimates may be different from the quantities of oil, natural gas and NGLs that are ultimately recovered.

The passage of time provides more qualitative information regarding estimates of reserves, and revisions are made to prior estimates to reflect updated information. The weighted average annual revisions to our reserve estimates have been less than 2% of the weighted average previous year's estimate (excluding revisions due to price changes). However, there can be no assurance that more significant revisions will not be necessary in the future. If future significant revisions are necessary that reduce previously estimated reserve quantities, it could result in a ceiling test-related impairment. In addition to the impact of the estimates of proved reserves on the calculation of the ceiling limitation, estimation of proved reserves is also a significant component of the calculation of depletion expense. For example, if estimates of proved reserves decline, the depletion rate will increase, resulting in a decrease in net income.

Full Cost Ceiling Calculations

Policy Description

We use the full cost method to account for our oil and gas properties. Under the full cost method, all costs associated with the development, exploration and acquisition of oil and gas properties are capitalized and accumulated in cost centers on a country-by-country basis. This includes any internal costs that are directly related to development and exploration activities, but does not include any costs related to production, general corporate overhead or similar activities. Proceeds received from disposals are credited against accumulated cost except when the sale represents a significant disposal of reserves, in which case a gain or loss is calculated and recognized. The application of the full cost method generally results in higher capitalized costs and higher depletion rates compared to its alternative, the successful efforts method. The sum of net capitalized costs and estimated future development and dismantlement costs for each cost center is depleted on the equivalent unit-of-production basis using estimated proved oil and gas reserves. Excluded from amounts subject to depletion are costs associated with unevaluated properties.

Under the full cost method, net capitalized costs are limited to the lower of unamortized cost reduced by the related net deferred tax liability and asset retirement obligations or the cost center ceiling. The cost center ceiling is defined as the sum of (1) estimated future net revenue, discounted at 10% per annum, from proved reserves, based on the unweighted average of the preceding 12-month first day-of the-month prices (year-end prices for 2008 and 2007) adjusted to reflect local differentials and contract provisions, unescalated year-end costs and financial derivatives that hedge the our oil and gas revenue, (2) the cost of properties not being amortized, (3) the lower of cost or market value of unproved properties included in the cost being amortized less (4) income tax effects related to differences between the book and tax bases of the oil and gas properties. If the net book value reduced by the related net deferred income tax liability and asset retirement obligations exceeds the cost center ceiling limitation, a non-cash impairment charge is required.

Judgments and Assumptions

The discounted present value of future net cash flows from our proved oil, natural gas and NGL reserves is the major component of the ceiling calculation, and is determined in connection with the estimation of our proved oil, natural gas and NGL reserves. Estimates of reserves are forecasts based on engineering data, projected future rates of production and the timing of future expenditures. The process of reserve estimation requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. Different reserve engineers may make different estimates of reserve quantities based on the same data.

While the quantities of proved reserves require substantial judgment, the associated prices of natural gas, NGL and oil reserves, and the applicable discount rate, that are used to calculate the discounted present value of the reserves do not require judgment. Current SEC rules require the use of the future net cash flows from proved reserves discounted at 10%. Therefore, the future net cash flows associated with the estimated proved reserves is not based on our assessment of future prices or costs. In calculating the ceiling, we adjust the future net cash flows by the discounted value of derivative contracts in place that hedge future prices. This valuation is determined by calculating the difference between reserve pricing and the contract prices for such hedges also discounted at 10%.

Because the ceiling calculation dictates that our historical experience, excluding the effects of benefits derived from our ownership of KGS, be held constant indefinitely and requires a 10% discount factor, the resulting value is not necessarily indicative of the fair value of the reserves or the oil and gas properties. Oil and natural gas prices have historically been volatile. At any period end, forecasted prices can be either substantially higher or lower than our historical experience. Also, marginal borrowing rates may be well below the required 10% used in the calculation. Rates below 10%, if they could be utilized, would have the effect of increasing the otherwise calculated ceiling amount. Therefore, oil and gas property ceiling test-related impairments that result from applying the full cost ceiling limitation, and that are caused by fluctuations in price as opposed to reductions to the underlying quantities of reserves, should not be viewed as absolute indicators of a reduction of the ultimate value of the related reserves.

Derivative Instruments

Policy Description

We enter into financial derivative instruments to mitigate risk associated with the prices received from our production. We may also utilize financial derivative instruments to hedge the risk associated with interest rates on our outstanding debt. We account for our derivative instruments by recognizing qualifying derivative instruments on our balance sheet as either assets or liabilities measured at their fair value determined by reference to published future market prices and interest rates.

For derivative instruments that qualify as cash flow hedges, the effective portions of gains or losses are deferred in other comprehensive income and recognized in earnings during the period in which the hedged transactions are realized. Gains or losses on qualified derivative instruments terminated prior to their original expiration date are deferred and recognized as income or expense in the period in which the hedged transaction is recognized. If the hedged transaction becomes probable of not occurring, the deferred gain or loss would be immediately recorded to earnings. The ineffective portion of the hedge relationship is recognized currently as a component of other revenue.

The fair values of our natural gas and NGL derivatives and the Gas Purchase Commitment as of December 31, 2009 were estimated using published market prices of natural gas and NGLs for the periods covered by the contracts. Estimates were determined by applying the net differential between the prices in each derivative and commitment and market prices for future periods, to the volumes stipulated in each contract to arrive at an estimated value of future cash flow streams. These estimated future cash flow values were then discounted for each contract at rates commensurate with federal treasury instruments with similar contractual lives to arrive at estimated fair value.

For derivative instruments that qualify as fair value hedges the gains or losses on the derivative instruments are recognized currently in earnings while the gains or losses on the hedged items adjust the carrying value of the hedged items and are recognized currently in earnings. Any gains or losses on the derivative instruments not offset by the gains or losses on the hedged items are recognized as the value of ineffectiveness in the hedge relationships. For interest rate swaps that qualify as fair value hedges of our fixed-rate debt outstanding, ineffectiveness is recognized currently as a component of interest expense.

The fair value of our interest rate derivatives was estimated using published LIBOR interest rates for the periods covered by the contracts. The estimates were determined by applying the net differential between the interest rate in each derivative and interest rates for future periods, to the notional amount stipulated in each contract to arrive at estimated future cash flow streams.

Judgments and Assumptions

The estimates of the fair values of our commodity and interest rate derivative instruments require substantial judgment. Valuations are based upon multiple factors such as futures prices, volatility data from major oil and gas trading points, time to maturity and interest rates. We compare our estimates of fair value for these instruments with valuations obtained from independent third parties and counterparty valuation confirmations. The values we report in our financial statements change as these estimates are revised to reflect actual results. Future changes to forecasted or realized commodity prices could result in significantly different values and realized cash flows for such instruments.

Stock-based Compensation

Policy Description

An estimate of fair value is determined for all share-based payment awards. Recognition of compensation expense for all share-based payment awards is recognized over the vesting period for each award.

Judgments and Assumptions

Option-pricing models and generally accepted valuation techniques require management to make assumptions and to apply judgment to determine the fair value of our awards. These assumptions and judgments include estimating the future volatility of our stock price, expected dividend yield, future employee turnover rates and future employee stock option exercise behaviors. Changes in these assumptions can materially affect the fair value estimate.

We do not believe there is a reasonable likelihood that there will be a material change in the future estimates or assumptions that we use to determine stock-based compensation expense. However, if actual results are not consistent with our estimates or assumptions, we may be exposed to changes in stock-based compensation expense that could be material. If actual results are not consistent with the assumptions used, the stock-based compensation expense reported in our financial statements may not be representative of the actual economic cost of the stock-based compensation.

Income Taxes

Policy Description

Deferred income taxes are established for all temporary differences between the book and the tax basis of assets and liabilities. In addition, deferred tax balances must be adjusted to reflect tax rates that we expect will be in effect during years in which we expect the temporary differences will reverse. Canadian taxes are computed at rates in effect or expected to be in effect in Canada. U.S. deferred tax liabilities are not recognized on profits that are expected to be permanently reinvested in Canada and thus are not considered available for distribution to us. Net operating loss carry forwards and other deferred tax assets are reviewed annually for recoverability, and if necessary, are recorded net of a valuation allowance.

Judgments and Assumptions

We must assess the likelihood that deferred tax assets will be recovered from future taxable income and provide judgment on the amount of financial statement benefit that an uncertain tax position will realize upon ultimate settlement. To the extent that we believe that a more than 50% probability exists that some portion or all of the deferred tax assets will not be realized, we must establish a valuation allowance. Significant management judgment is required in determining any valuation allowance recorded against deferred tax assets and in determining the amount of financial statement benefit to record for uncertain tax positions. We consider all available evidence, both positive and negative, to determine whether, based on the weight of the evidence, a valuation allowance is needed and consider the amounts and probabilities of the outcomes that could be realized upon ultimate settlement of an uncertain tax position using the facts, circumstances and information available at the reporting date to establish the appropriate amount of financial statement benefit. Evidence used for the valuation allowance includes information about our current financial position and results of operations for the current and preceding years, as well as all currently available information about future years, including our anticipated future performance, the reversal of deferred tax assets and liabilities and tax planning strategies available to us. To the extent that a valuation allowance or uncertain tax position is established or changed during any period, we would recognize expense or benefit within our consolidated tax expense.

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 2 to our consolidated financial statements in Item 8 of this Annual Report, which is incorporated herein by reference.

ITEM 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

We enter into financial derivative contracts to mitigate our exposure to commodity price risk associated with anticipated future production and to increase the predictability of our revenue. As of December 31, 2009, forecasted natural gas production of 200 MMcfd has been hedged with natural gas price collars and 10 MBbld of forecasted NGL production has been hedged with NGL price swaps for 2010. Additionally, 120 MMcfd of natural gas price collars and 5 MBbld of NGL price swaps have been executed to hedge anticipated 2011 production and 60 MMcfd of 2012 anticipated natural gas production has been hedged using natural gas price collars.

Utilization of our financial hedging program will most often result in realized prices from the sale of our natural gas, NGL and oil that vary from market prices. As a result of settlements of derivative contracts, our revenue from natural gas, NGL and oil production was $310.9 million higher for 2009, $18.4 million lower for 2008 and $51.1 million higher for 2007, respectively.

The following table details our open derivative positions as of December 31, 2009 and those we have entered into after that date related to our anticipated natural gas and NGL production:

Product	Type	Contract Period	Volume	Weighted Avg Price Per Mcf or Bbl	Fair Value
					(In thousands)
Gas	Collar	Jan 2010-Dec 2010	20 MMcfd	$ 8.00-11.00	$ 17,163
Gas	Collar	Jan 2010-Dec 2010	20 MMcfd	8.00-11.00	17,163
Gas	Collar	Jan 2010-Dec 2010	20 MMcfd	8.00-12.20	17,289
Gas	Collar	Jan 2010-Dec 2010	20 MMcfd	8.00-12.20	17,289
Gas	Collar	Jan 2010-Dec 2010	10 MMcfd	8.50-12.05	10,320
Gas	Collar	Jan 2010-Dec 2010	20 MMcfd	8.50-12.05	20,640
Gas	Collar	Jan 2010-Dec 2010	10 MMcfd	8.50-12.08	10,328
Gas	Collar	Jan 2010-Dec 2011	10 MMcfd	6.00-7.00	1,921
Gas	Collar	Jan 2010-Dec 2011	10 MMcfd	6.00-7.00	1,921
Gas	Collar	Jan 2010-Dec 2011	20 MMcfd	6.00-7.00	3,843
Gas	Collar	Jan 2010-Dec 2012	20 MMcfd	6.50-7.15	10,456
Gas	Collar	Jan 2010-Dec 2012	20 MMcfd	6.50-7.18	10,993
Gas	Collar	Jan 2011-Dec 2011	10 MMcfd	6.25-7.50	1,187
Gas	Collar	Jan 2011-Dec 2011	10 MMcfd	6.25-7.50	1,187
Gas	Collar	Jan 2011-Dec 2011	20 MMcfd	6.25-7.50	2,374
Gas	Collar	Jan 2012-Dec 2012	20 MMcfd	6.50-8.01	3,277
Gas	Basis	Jan 2010-Dec 2010	20 MMcfd	(1)	(638)
Gas	Basis	Jan 2010-Dec 2010	20 MMcfd	(1)	(638)
Gas	Basis	Jan 2011-Dec 2011	10 MMcfd	(1)	122
Gas	Basis	Jan 2011-Dec 2011	10 MMcfd	(1)	122
Gas	Basis	Jan 2011-Dec 2011	20 MMcfd	(1)	243
NGL	Swap	Jan 2010-Dec 2010	2 MBld	$ 32.65	(6,930)
NGL	Swap	Jan 2010-Dec 2010	3 MBld	32.98	(9,752)
NGL	Swap	Jan 2010-Dec 2010	1 MBld	33.63	(3,108)
NGL	Swap	Jan 2010-Dec 2010	1 MBld	34.15	(2,980)
NGL	Swap	Jan 2010-Dec 2010	3 MBld	34.22	(8,397)
NGL	Swap	Jan 2011-Dec 2011	3 MBld	36.06	(4,333)
NGL	Swap	Jan 2011-Dec 2011	2 MBld	36.31	(3,181)
				Total	$ 107,881

(1) Basis swaps hedge the AECO basis adjustment at a deduction of $0.45 per Mcf from NYMEX for 2010 and $0.39 per Mcf from NYMEX for 2011.

Since December 31, 2009, we have entered into the following NGL and natural gas basis swaps:

Product	Type	Contract Period	Volume	Weighted Avg Price Per Mcf or Bbl
NGL	Swap	Jan 2011-Dec 2011	3 MBbld	$ 41.95
Gas	Basis	Feb 2010-Dec 2010	20 MMcfd	(2)
Gas	Basis	Apr 2010-Dec 2010	10 MMcfd	(3)
Gas	Basis	Apr 2010-Dec 2010	10 MMcfd	(3)

(2) Basis swap hedges the Houston Ship Channel basis adjustment at a deduction of $0.09 per Mcf from NYMEX for February through December 2010.

(3) Basis swaps hedge the Houston Ship Channel basis adjustment at deductions of $0.45 and $0.425 per Mcf, respectively, from NYMEX for April through December 2010.

Based on information available on June 19, 2009, we recognized a liability pursuant to the Gas Purchase Commitment for the estimated production volumes attributable to Eni through December 31, 2010, which then totaled 22.2 Bcf. The remaining Gas Purchase Commitment is adjusted to fair value throughout the period of the commitment, which expires on December 31, 2010. We recognized a $6.6 million increase in the remaining liability between June 19 and December 31, 2009 and recorded a valuation loss as a component of costs of purchased natural gas. At December 31, 2009, we had a remaining liability of $50.7 million, including the $6.6 million liability for the change in value since initial valuation. The following summarizes activity to the Gas Purchase Commitment:

(In thousands)	
Initial valuation of liability(1)	$ 58,294
Decrease due to gas volumes purchased	(14,175)
Embedded derivative increase (decrease) due to:	
Price changes	7,904
Volume changes	(1,279)
Total embedded derivative	6,625
Balance at December 31, 2009	$ 50,744

(1) Initial valuation of the Gas Purchase Commitment was estimated using estimated Eni production volumes from June 19, 2009 through December 2010 and published future market prices and risk-adjusted interest rates as of June 19, 2009.

Interest Rate Risk

The interest income or expense from our interest rate swaps is accrued as earned and recorded as an adjustment to the interest expense accrued on two fixed-rate debt issues, our senior notes due 2015 and our senior subordinated notes. These interest rate swaps qualified and were accounted for as fair value hedges. During 2009 settlements under the interest rate swaps decreased interest expense by $13.7 million, which resulted in average effective interest rates of approximately 5.1% and 3.7% on the senior notes due 2015 and the senior subordinated debt, respectively.

In February 2010, we executed early settlement of our interest rate swaps on our senior notes due 2015 and our senior subordinated notes. We received cash of $18.0 million in the settlement, which has been recorded as an adjustment to the carrying value of the debt and will be amortized to earnings over the life of the associated underlying debt instruments.

We subsequently entered into new interest rate swaps on our senior notes due 2015 and our senior subordinated notes that convert the interest paid on those issues from a fixed to a floating rate indexed to six-month LIBOR. The maturity dates and all other significant terms are the same as those of the underlying debt. As a result, these interest rate swaps qualified for hedge accounting treatment as fair value hedges.

Foreign Currency Risk

Our Canadian subsidiary uses the Canadian dollar as its functional currency. To the extent that business transactions in Canada are not denominated in Canadian dollars, we are exposed to foreign currency exchange rate risk. For 2009, 2008 and 2007, non-functional currency transactions resulted in losses of $2.2 million, $3.3 million and $0.8 million, respectively, included in net earnings. Furthermore, the Senior Secured Credit Facility permits Canadian borrowings to be made in either U.S. or Canadian-denominated amounts. However, the aggregate borrowing capacity of the entire facility is calculated using the U.S. dollar equivalent. Accordingly, there is a risk that exchange rate movements could impact our available borrowing capacity.

ITEM 8. Financial Statements and Supplementary Data

QUICKSILVER RESOURCES INC.
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Quicksilver Resources Inc.
Fort Worth, Texas

We have audited the accompanying consolidated balance sheets of Quicksilver Resources Inc. and subsidiaries (the "Company") as of December 31, 2009 and 2008, and the related consolidated statements of income (loss) and comprehensive income (loss), equity, and cash flows for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Quicksilver Resources Inc. and subsidiaries at December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, on December 31, 2009, the Company adopted Accounting Standards Update No. 2010-3, "Oil and Gas Reserve Estimation and Disclosures."

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2009, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 15, 2010 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Fort Worth, Texas
March 15, 2010

QUICKSILVER RESOURCES INC.
CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)
FOR THE YEARS ENDED DECEMBER 31, 2009, 2008 AND 2007
In thousands, except for per share data

	2009	2008	2007
Revenue			
Natural gas, NGL and oil	$ 796,698	$ 780,788	$ 545,089
Sales of purchased natural gas	23,654	-	-
Other	12,383	19,853	16,169
Total revenue	832,735	800,641	561,258
Operating expense			
Oil and gas production expense	127,715	134,302	136,103
Production and ad valorem taxes	23,881	18,734	17,048
Costs of purchased natural gas	30,158	-	-
Other operating expense	6,684	3,337	2,614
Depletion, depreciation and accretion	201,387	188,196	120,697
General and administrative expense	77,243	72,254	47,060
Total expense	467,068	416,823	323,522
Impairment related to oil and gas properties	(979,540)	(633,515)	-
Income from equity affiliates	-	-	661
Gain on sale of oil and gas properties	-	-	628,709
Loss on natural gas sales contract	-	-	(63,525)
Operating income (loss)	(613,873)	(249,697)	803,581
Income from earnings of BBEP	75,444	93,298	-
Impairment of investment in BBEP	(102,084)	(320,387)	-
Other income (expense) – net	(1,242)	807	3,887
Interest expense	(195,101)	(109,098)	(76,662)
Income (loss) before income taxes	(836,856)	(585,077)	730,806
Income tax (expense) benefit	291,617	211,455	(254,361)
Net income (loss)	(545,239)	(373,622)	476,445
Net income attributable to noncontrolling interests	(12,234)	(4,654)	(1,055)
Net income (loss) attributable to Quicksilver	$ (557,473)	$ (378,276)	$ 475,390
Other comprehensive income (loss)			
Reclassification adjustments related to settlements of derivative contracts – net of income tax	(211,863)	11,969	(34,648)
Net change in derivative fair value – net of income tax	125,989	182,472	(14,794)
Foreign currency translation adjustment	22,106	(49,403)	29,409
Comprehensive income (loss)	$ (621,241)	$ (233,238)	$ 455,357
Earnings (loss) per common share – basic	$ (3.30)	$ (2.33)	$ 3.04
Earnings (loss) per common share – diluted	$ (3.30)	$ (2.33)	$ 2.87
Basic weighted average shares outstanding	169,004	162,004	156,517
Diluted weighted average shares outstanding	169,004	162,004	168,029

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

QUICKSILVER RESOURCES INC.
CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2009 AND 2008
In thousands, except for share data

	2009	2008
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,785	$ 2,848
Accounts receivable – net of allowance for doubtful accounts	65,253	143,315
Derivative assets at fair value	97,957	171,740
Other current assets	54,943	75,433
Total current assets	219,938	393,336
Investments in equity affiliates	112,763	150,503
Property, plant and equipment – net		
Oil and gas properties, full cost method (including unevaluated costs of $458,037 and $543,533, respectively)	2,338,244	3,142,608
Other property and equipment	747,696	655,107
Property, plant and equipment – net	3,085,940	3,797,715
Derivative assets at fair value	14,427	116,006
Deferred income taxes	133,051	–
Other assets	46,763	40,648
	$ 3,612,882	$ 4,498,208
LIABILITIES AND EQUITY		
Current liabilities		
Current portion of long-term debt	$ –	$ 6,579
Accounts payable	157,986	282,636
Accrued liabilities	156,604	66,963
Derivative liabilities at fair value	395	9,928
Current deferred tax liability	51,675	52,393
Total current liabilities	366,660	418,499
Long-term debt	2,427,523	2,586,045
Asset retirement obligations	59,268	34,753
Other liabilities	20,691	12,962
Deferred income taxes	41,918	234,386
Commitments and contingencies (Note 16)		
Equity		
Preferred stock, par value $0.01, 10,000,000 shares authorized, none outstanding	–	–
Common stock, $0.01 par value, 400,000,000 and 200,000,000 shares authorized, respectively; 174,469,836 and 171,742,699 shares issued, respectively	1,745	1,717
Paid in capital in excess of par value	730,265	656,958
Treasury stock of 4,704,448 and 4,572,795 shares, respectively	(36,363)	(35,441)
Accumulated other comprehensive income	121,336	185,104
Retained earnings (deficit)	(180,985)	376,488
Quicksilver stockholders' equity	635,998	1,184,826
Noncontrolling interests	60,824	26,737
Total equity	696,822	1,211,563
	$ 3,612,882	$ 4,498,208

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

QUICKSILVER RESOURCES INC.
CONSOLIDATED STATEMENTS OF EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2009, 2008 AND 2007
In thousands, except for share data

	Quicksilver Resources Inc. Stockholders' Equity						
	Common Stock	Additional Paid-in Capital	Treasury Stock	Accumulated Other Comprehensive Income	Retained Earnings	Noncontrolling Interest	Total
Balances at December 31. 2006	$ 1,578	$ 264,078	$ (10,737)	$ 60,099	$ 279,719	$ 7,382	$ 602,119
Net income	-	-	-	-	475,390	1,055	476,445
Adoption of new rules for uncertain tax positions	-	-	-	-	(345)	-	(345)
Hedge derivative contract settlements reclassified into earnings from accumulated other comprehensive income, net of income tax of $16,491	-	-	-	(34,648)	-	-	(34,648)
Net change in derivative fair value, net income tax of $8,436	-	-	-	(14,794)	-	-	(14,794)
Foreign currency translation adjustment	-	-	-	29,409	-	-	29,409
Issuance & vesting of stock compensation	6	13,863	(1,567)	-	-	129	12,431
Stock option exercises, including income tax benefits	22	21,365	-	-	-	-	21,387
Issuance of KGS common units	-	79,316	-	-	-	29,942	109,258
Distributions paid on KGS common units	-	-	-	-	-	(8,794)	(8,794)
Balances at December 31. 2007	1,606	378,622	(12,304)	40,066	754,764	29,714	1,192,468
Net income (loss)	-	-	-	-	(378,276)	4,654	(373,622)
Hedge derivative contract settlements reclassified into earnings from accumulated other comprehensive income, net of income tax of $6,424	-	-	-	11,969	-	-	11,969
Net change in derivative fair value, net income tax of $93,251	-	-	-	182,472	-	-	182,472
Foreign currency translation adjustment	-	-	-	(49,403)	-	-	(49,403)
Issuance & vesting of stock compensation	5	15,106	(3,237)	-	-	1,013	12,887
Stock option exercises	2	1,242	-	-	-	-	1,244
Issuance of common stock – Alliance Acquisition	104	261,988	-	-	-	-	262,092
Acquisition of treasury stock	-	-	(19,900)	-	-	-	(19,900)
Distributions paid on KGS common units	-	-	-	-	-	(8,644)	(8,644)
Balances at December 31. 2008	1,717	656,958	(35,441)	185,104	376,488	26,737	1,211,563
Net income (loss)	-	-	-	-	(557,473)	12,234	(545,239)
Hedge derivative contract settlements reclassified into earnings from accumulated other comprehensive income, net of income tax of $99,004	-	-	-	(211,863)	-	-	(211,863)
Net change in derivative fair value, net income tax of $57,007	-	-	-	125,989	-	-	125,989
Foreign currency translation adjustment	-	-	-	22,106	-	-	22,106
Issuance & vesting of stock compensation	22	19,085	(922)	-	-	1,645	19,830
Stock option exercises	6	4,040	-	-	-	-	4,046
Issuance of KGS common units	-	50,182	-	-	-	30,133	80,315
Distributions paid on KGS common units	-	-	-	-	-	(9,925)	(9,925)
Balances at December 31. 2009	$ 1,745	$ 730,265	$ (36,363)	$ 121,336	$ (180,985)	$ 60,824	$ 696,822

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

QUICKSILVER RESOURCES INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS END DECEMBER 31, 2009, 2008 AND 2007
In thousands

	2009	2008	2007
Operating activities:			
Net income (loss)	$ (545,239)	$ (373,622)	$ 476,445
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and accretion	201,387	188,196	120,697
Impairment related to oil and gas properties	979,540	633,515	-
Deferred income tax expense (benefit)	(291,414)	(166,440)	207,796
(Gain) loss from sale of property, plant and equipment	-	605	(627,348)
Non-cash (gain) loss from hedging and derivative activities	6,756	(1,139)	62,515
Stock-based compensation	20,752	16,128	11,243
Non-cash interest expense	45,532	13,215	10,374
Income from BBEP in excess of cash distributions	(64,344)	(50,762)	-
Impairment of investment in BBEP	102,084	320,387	-
Other	747	-	(349)
Divestiture expenses	-	-	2,015
Changes in assets and liabilities			
Accounts receivable	77,527	(53,071)	(14,423)
Derivative assets at fair value	54,896	-	-
Prepaid expenses and other assets	3,061	(5,448)	(4,805)
Accounts payable	(12,320)	7,602	18,939
Income taxes payable	-	(46,561)	46,012
Accrued and other liabilities	33,275	(26,039)	9,993
Net cash provided by operating activities	612,240	456,566	319,104
Investing activities:			
Purchases of property, plant and equipment	(693,838)	(1,286,715)	(1,020,684)
Alliance Acquisition	-	(993,212)	-
Return of investment from equity affiliates	-	-	9,635
Proceeds from sales of properties and equipment	220,974	1,339	741,297
Net cash used in investing activities	(472,864)	(2,278,588)	(269,752)
Financing activities:			
Issuance of debt	1,420,727	2,948,672	817,821
Repayments of debt	(1,649,630)	(1,096,163)	(968,557)
Debt issuance costs paid	(32,472)	(25,219)	(5,130)
Gas Purchase Commitment	58,294	-	-
Gas Purchase Commitment repayments	(14,175)	-	-
Issuance of KGS common units – net offering costs	80,729	-	109,809
Distributions paid on KGS common units	(9,925)	(8,644)	(8,794)
Proceeds from exercise of stock options	4,046	1,244	21,387
Excess tax benefits on exercise of stock options	-	-	2,755
Purchase of treasury stock	(922)	(23,137)	(1,567)
Net cash provided by (used in) financing activities	(143,328)	1,796,753	(32,276)
Effect of exchange rate changes in cash	2,889	(109)	5,869
Net increase (decrease) in cash	(1,063)	(25,378)	22,945
Cash and cash equivalents at beginning of period	2,848	28,226	5,281
Cash and cash equivalents at end of period	$ 1,785	$ 2,848	$ 28,226

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

1. NATURE OF OPERATIONS

Quicksilver Resources Inc. is an independent oil and gas company incorporated in the state of Delaware and headquartered in Fort Worth, Texas. We engage in the exploration, development, exploitation, acquisition, production and sale of natural gas, NGLs and oil as well as the marketing, processing and transportation of natural gas. As of December 31, 2009, our significant oil and gas reserves and operations are located in Texas, the U.S. Rocky Mountains and Alberta and British Columbia, Canada. We have offices located in Fort Worth, Texas, Cut Bank, Montana, Glen Rose, Texas and in Calgary, Alberta. Until we completed the BreitBurn Transaction in 2007 (see Note 5), we also had significant oil and gas reserves and operations in Michigan, Indiana and Kentucky.

Our results of operations are largely dependent on the difference between the prices received for our natural gas, NGL and oil products and the cost to find, develop, produce and market such resources. Natural gas, NGL and oil prices are subject to fluctuations in response to changes in supply, market uncertainty and a variety of other factors beyond our control. These factors include worldwide political instability, quantities of natural gas in storage, foreign supply of natural gas and oil, the price of foreign imports, the level of consumer demand and the price of available alternative fuels. We actively manage a portion of the financial risk relating to natural gas, NGL and oil price volatility through derivative contracts.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

Our consolidated financial statements include the accounts of Quicksilver and all its majority-owned subsidiaries and companies over which we exercise control through majority voting rights. We eliminate all inter-company balances and transactions in preparing consolidated financial statements. We account for our ownership in unincorporated partnerships and companies, including BBEP, under the equity method when we have significant influence over those entities, but because of terms of the ownership agreements, we do not meet the criteria for control which would require consolidation of the entities.

Our consolidated financial statements reflect the adoption of new U.S. accounting standards in 2009, which include the presentation of noncontrolling interests (previously referred to as "minority interest"), accounting for contingently convertible debt and a revision to the calculation of basic earnings per share for unvested share-based compensation with nonforfeitable rights to dividends. Further discussion of the effects of these accounting standards is found in Note 2 to our consolidated financial statements in Item 8 of our 2008 Annual Report on Form 10-K, as amended and filed June 17, 2009.

Changes in Presentation

Certain reclassifications have been made to the 2008 and 2007 financial statements for presentations adopted in 2009.

Stock Split

On January 7, 2008, we announced that our Board of Directors declared a two-for-one stock split of Quicksilver's outstanding common stock effected in the form of a stock dividend. The stock dividend was payable on January 31, 2008, to holders of record at the close of business on January 18, 2008. The split had no effect on shares held in treasury. The capital accounts, all share data and earnings per share data included in these consolidated financial statements for all years presented have been adjusted to retroactively reflect the January 2008 stock split.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires our management to make estimates and assumptions that affect the reported amounts of certain assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during each reporting period. Management believes its estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties, which may cause actual results to differ materially from management's estimates.

Significant estimates underlying these financial statements include the estimated quantities of proved natural gas, NGL and oil reserves (including the associated future net cash flows from those proved reserves) used to compute depletion expense and estimates of current revenue based upon expectations for actual deliveries and prices received. Other estimates that require the assumptions concerning future events and substantial judgment include the estimated fair values of financial derivative instruments, asset retirement obligations and employee stock-based compensation. Income taxes also involve the use of considerable judgment in the estimation and evaluation of deferred income tax assets and our ability to recover operating loss carryforwards and assessment of uncertain tax positions.

Cash and Cash Equivalents

Cash equivalents consist of time deposits and liquid debt investments with original maturities of three months or less at the time of purchase.

Accounts Receivable

We sell our natural gas, NGL and oil production to various purchasers. Each of our counterparties is reviewed as to credit worthiness prior to the extension of credit and on a regular basis thereafter. Although we do not require collateral, appropriate credit ratings are required and, in some instances, parental guarantees are obtained. Receivables are generally due in 30-60 days. When collections of specific amounts due are no longer reasonably assured, we establish an allowance for doubtful accounts. During 2009, three purchasers individually accounted for 15%, 13% and 10% of our consolidated natural gas, NGL and oil sales. During 2008, two purchasers individually accounted for 17% and 10% of our consolidated natural gas, NGL and oil sales.

Hedging and Derivatives

We enter into financial derivative instruments to mitigate risk associated with the prices received from our natural gas, NGL and oil production. We may also utilize financial derivative instruments to hedge the risk associated with interest rates on our outstanding debt. All derivatives are recognized as either an asset or liability on the balance sheet measured at their fair value determined by reference to published future market prices and interest rates.

For derivatives instruments that qualify as cash flow hedges, the effective portions of gains and losses are deferred in other comprehensive income and recognized in revenue or interest expense in the period in which the hedged transaction is recognized. Gains or losses on derivative instruments terminated prior to their original expiration date are deferred and recognized as earnings during the period in which the hedged transaction is recognized. If the hedged transaction becomes probable of not occurring, the deferred gain or loss would be immediately recorded to earnings. Changes in value of ineffective portions of hedges, if any, are recognized currently as a component of other revenue.

For derivative instruments that qualify as fair value hedges the gains or losses on the derivative instruments are recognized currently in earnings while the gains or losses on the hedged items shall adjust the carrying value of the hedged items and be recognized currently in earnings. Any gains or losses on the derivative instruments not offset by the gains or losses on the hedged items are recognized as the value of ineffectiveness in the hedge relationships. For interest rate swaps that qualify as fair value hedges of our fixed-rate debt outstanding, ineffectiveness is recognized currently as a component of interest expense.

We enter into financial derivatives with counterparties who are lenders under our Senior Secured 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 fair value for each derivative takes into consideration credit risk, whether it be our counterparties' or our own. Derivatives are recorded in the balance sheet as current and non-current derivative assets and liabilities as determined by the expected timing of settlements.

Until December 2007, the Michigan Sales Contract, which required delivery of 25 MMcfd of owned or controlled natural gas at a floor of $2.49 per Mcf through March 2009, had been excluded from derivatives as it was designated as a normal sales contract under GAAP. In December 2007 and in connection with the divestiture of the Northeast Operations, we decided to cease delivering a portion of our natural gas production to supply the contractual volumes. As the contract no longer qualified under the normal sales exclusion under GAAP, we recognized a loss of $63.5 million at that time.

Until May 2007, we also had another long-term contract (the "CMS Contract") for delivery of 10 MMcfd of owned or controlled natural gas at a floor price of $2.47 that was treated as a normal sales contract under GAAP. See Note 5 to these consolidated financial statements for more information regarding the CMS Contract.

Investments in Equity Affiliates

Income from equity affiliates is included as a component of operating income when the operations of the affiliates are associated with processing and gathering of our natural gas production.

We account for our investment in BBEP using the equity method. We review our investment for impairment whenever events or circumstances indicate that the investment's carrying amount may not be recoverable. We record our portion of BBEP's earnings during the quarter in which their financial statements become publicly available. As a result, our 2009 annual results of operations include BBEP's earnings for the 12 months ended September 30, 2009. Our 2008 results of operations reflect BBEP's earnings from November 1, 2007, when we acquired BBEP units, through September 30, 2008. We are not aware of any significant events or transactions subsequent to September 30, 2009 that will affect BBEP's results of operations after that date. See Note 9 for more information on our BBEP investment.

Property, Plant, and Equipment

We follow the full cost method in accounting for our oil and gas properties. Under the full cost method, all costs associated with the acquisition, exploration and development of oil and gas properties are capitalized and accumulated in cost centers on a country-by-country basis. This includes any internal costs that are directly related to development and exploration activities, but does not include any costs related to production, general corporate overhead or similar activities. Proceeds received from disposals are credited against accumulated cost except when the sale represents a significant disposal of reserves, in which case a gain or loss is recognized. The sum of net capitalized costs and estimated future development and dismantlement costs for each cost center is depleted on the equivalent unit-of-production method, based on proved oil and gas reserves. Excluded from amounts subject to depletion are costs associated with unevaluated properties.

Under the full cost method, net capitalized costs are limited to the lower of unamortized cost reduced by the related net deferred tax liability and asset retirement obligations or the cost center ceiling. The cost center ceiling is defined as the sum of (1) estimated future net revenue, discounted at 10% per annum, from proved reserves, based on the unweighted average of the preceding 12-month of first-day-of-the-month prices adjusted to reflect local differentials and contract provisions, year end costs and financial derivatives that hedge our oil and gas revenue, (2) the cost of properties not being amortized, (3) the lower of cost or market value of unproved properties included in the cost being amortized less (4) income tax effects related to differences between the book and tax basis of the natural gas and oil properties. If the net book value reduced by the related net deferred income tax liability and asset retirement obligations exceeds the cost center ceiling limitation, a non-cash impairment charge is required. Note 10 to these financial statements contains further discussion of the ceiling test.

All other properties and equipment are stated at original cost and depreciated using the straight-line method based on estimated useful lives ranging from five to forty years.

Asset Retirement Obligations

We record the fair value of the liability for asset retirement obligations in the period in which it is legally or contractually incurred. Upon initial recognition of the asset retirement liability, an asset retirement cost is capitalized by increasing the carrying amount of the asset by the same amount as the liability. In periods subsequent to initial measurement, the asset retirement cost is recognized as expense through depletion or depreciation over the asset's useful life. Changes in the liability for the asset retirement obligations are recognized for (1) the passage of time and (2) revisions to either the timing or the amount of estimated cash flows. Accretion expense is recognized for the impacts of increasing the discounted fair value to its estimated settlement value.

Revenue Recognition

Revenue is recognized when title to the products transfer to the purchaser. We use the "sales method" to account for our production revenue, whereby we recognize revenue on all natural gas, NGL or oil sold to our purchasers, regardless of whether the sales are proportionate to our ownership in the property. A receivable or liability is recognized only to the extent that we have an imbalance on a specific property greater than the expected remaining proved reserves. As of December 31, 2009 and 2008, our aggregate production imbalances were not material.

Environmental Compliance and Remediation

Environmental compliance costs, including ongoing maintenance and monitoring, are expensed as incurred. Those environmental remediation costs which improve a property are capitalized.

Debt

We record all debt instruments at face value. When an issuance of debt is made at other than par, a discount or premium is separately recorded. The discount or premium is amortized over the life of the debt using the effective interest method. As required by GAAP, we have separately accounted for the liability and equity components of our contingently convertible debt instrument. Such recording has resulted in recognition of interest expense at our effective borrowing rate in effect at the time of issuance.

Income Taxes

Deferred income taxes are established for all temporary differences between the book and the tax basis of assets and liabilities. In addition, deferred tax balances must be adjusted to reflect tax rates expected to be in effect in years in which the temporary differences reverse. Canadian taxes are calculated at rates expected to be in effect in Canada. U.S. deferred tax liabilities are not recognized on profits that are expected to be permanently reinvested in Canada and thus not considered available for distribution to the parent company. Net operating loss carry forwards and other deferred tax assets are reviewed annually for recoverability, and if necessary, are recorded net of a valuation allowance.

Stock-based Compensation

We measure and recognize compensation expense for all share-based payment awards made to employees and directors based on their estimated fair value at the time the awards are granted. At the discretion of the board of directors, we may issue awards payable in cash. For all awards, we recognize the expense associated with the awards over the vesting period. The liability for fair value of cash awards is reassessed at every balance sheet date, such that the vested portion of the liability is adjusted to reflect revised fair value through compensation expense.

Disclosure of Fair Value of Financial Instruments

Our financial instruments include cash, time deposits, accounts receivable, notes payable, accounts payable, long-term debt and financial derivatives. The fair value of long-term debt is estimated as the present value of future cash flows discounted at rates consistent with comparable maturities and includes consideration of credit risk. The carrying amounts reflected in the balance sheet for financial assets classified as current assets and the carrying amounts for financial liabilities classified as current liabilities approximate fair value.

Foreign Currency Translation

Our Canadian subsidiary uses the Canadian dollar as its functional currency. All balance sheet accounts of the Canadian operations are translated into U.S. dollars at the period end rate of exchange and statement of income items are translated at the weighted average exchange rates for the period. The resulting translation adjustments are made directly to a component of accumulated other comprehensive income within stockholders' equity. Gains and losses from foreign currency transactions are included in the consolidated results of operations.

Noncontrolling Interests in Consolidated Subsidiaries

Noncontrolling interests reflect the fractional outside ownership of our majority-owned and consolidated subsidiaries. Our adoption of new GAAP for noncontrolling interests on January 1, 2009 resulted in a reclassification of $29.9 million to equity and captioned as noncontrolling interests. Measurement of the income statement amounts attributable to noncontrolling ownership interests of KGS was unaffected by this adoption. We include the results of operations and financial position of KGS in our consolidated financial statements and recognize the portion of KGS' results of operations attributable to unaffiliated unitholders as a component of "income attributable to noncontrolling interests". Equity balances for noncontrolling interests do not necessarily reflect the fair value of that outside ownership.

Earnings per Share

We report basic earnings per common share, which excludes the effect of potentially diluted securities, and diluted earnings per common share, which includes the effect of all potentially dilutive securities unless their impact is antidilutive. The calculation of earnings per share is found at Note 18.

Recently Issued Accounting Standards

Accounting standard-setting organizations frequently issue new or revised accounting rules. We regularly review all new pronouncements to determine their impact, if any, on our financial statements. Below, we present a discussion of only those pronouncements that have or are expected to have an impact on our financial statements.

• **Pronouncements Impacting Quicksilver That Have Been Implemented During 2009**

GAAP guidance discussed below references only those items not previously included in Note 2 to our consolidated financial statements in Item 8 of our 2008 Annual Report on Form 10-K, as amended and filed June 17, 2009.

In June 2009 and through subsequent updates, the FASB issued guidance that identified the *FASB Accounting Standards Codification* as the single source of authoritative U.S. GAAP not promulgated by the SEC. The FASC retains existing GAAP and had no effect on our financial statements upon its adoption by us at adoption, although any references to GAAP herein have been converted to the codified reference.

The FASB issued revised guidance for business combinations in December 2007, which retained 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. The acquirer is the entity that obtains control in the business combination and the guidance establishes the criteria to determine the acquisition date. An acquirer is also required 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. Additional clarifications were issued on April 1, 2009 that address application issues regarding initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. Had we made or should we make any acquisition after January 1, 2009, when we adopted this revised guidance, we would have applied and will apply the guidance, but otherwise adoption had no effect on our financial statements.

In February 2008, the FASB issued guidance which allowed for a one-year deferral of the effective date of the accounting guidance in FASC Topic 820, *Fair Value Measurements and Disclosures,* as it applies to non-financial assets and liabilities that are recognized or disclosed at fair value on a nonrecurring basis. Beginning January 1, 2009, we applied the accounting guidance for all fair value measurements to non-financial assets and liabilities.

The FASB issued accounting guidance in March 2008 requiring enhanced disclosures of the fair value and other aspects of all derivative and hedging instruments 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 the guidance on January 1, 2009 and have provided the prescribed disclosures for all periods presented in Note 6.

On April 9, 2009, the FASB issued guidance, found at FASC Subtopic 825-10, *Financial Instruments,* requiring disclosures about fair value of financial instruments for interim reporting periods. We have adopted the disclosure requirements.

The FASB issued guidance in May 2009 for disclosure of events that occur after the balance sheet date but before financial statements are issued by public entities. It mirrors the longstanding existing guidance for subsequent events that was promulgated by the American Institute of Certified Public Accountants. We adopted the guidance during the quarter ended June 30, 2009 when the guidance became effective without effect.

The FASB issued updated disclosure guidance in August 2009, which updated FASC Topic 820, *Fair Value Measurements and Disclosures,* for the fair value measurement of liabilities. We have adopted all relevant guidance related to fair value measurement and disclosure.

The SEC adopted revisions to its required oil and gas reporting disclosures in December 2008. The revisions affecting us include: 1) use of the unweighted average of the preceding 12-month first-day-of-the-month prices for determination of proved reserve values included in calculating full cost ceiling limitations and for annual proved reserve disclosures; 2) consideration of and 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 full cost ceiling test for impairment. We have adopted these changes for the required supplemental reporting of our proved reserves and related disclosures as of and for the year ended December 31, 2009.

As a result of the SEC's new rule for oil and gas disclosures, the FASB issued updates to its guidance for oil and gas disclosures to incorporate those changes so that FASC requirements are consistent with the SEC's changes. Additionally the FASB adopted requirements for separate supplemental disclosures about oil and gas producing activities for equity method investments. We have adopted these changes and related disclosures as of and for the year ended December 31, 2009.

In 2010, the FASB amended guidance that addressed provisions equity-method investments and for changes in a parent's ownership interest in a consolidated subsidiary. Additionally, the FASB amended guidance for disclosure of recurrent fair value measurements. We adopted the changes as of and for the year ended December 31, 2009.

3. ENI TRANSACTION

On June 19, 2009, we completed the Eni Transaction whereby we entered into a strategic alliance with Eni and sold a 27.5% interest in our Alliance Leasehold. The assets were sold to Eni for $279.7 million in cash, inclusive of the Gas Purchase Commitment assumed and normal post-closing adjustments. We used the proceeds generated to repay a portion of the Senior Secured Second Lien Facility.

In connection with the sale, we entered into a gas gathering agreement with Eni covering Eni's production from the Alliance Leasehold. Under the agreement, we will gather, treat and deliver Eni's Alliance Leasehold production. Eni also committed to pay approximately $19.2 million by March 2010 to us (of which $9.5 million has been paid through December 31, 2009) for construction and installation of the facilities required to gather Eni's production from future Alliance wells. We will be the sole owner of these facilities and, upon completion of the Gas Purchase Commitment, will recognize gathering revenue for the volumes of gas that are gathered.

Also as part of the sale, we entered into a joint development agreement with Eni. The joint development agreement includes a schedule of wells that we agreed to drill and complete with participation by Eni during the development period. In connection with the scheduled drilling of these wells, we have committed to drill and complete a minimum number of lateral feet each year. Eni agreed to pay us a turnkey drilling and completion cost of $994 per linear foot attributable to Eni. The net linear footage requirements to be drilled and completed attributable to Eni are summarized below:

Year	Total Aggregate Linear Feet
2010	58,448
2011	44,080
2012	26,974
2013	34,102

Under the joint development agreement, we may be subject to pay Eni for damages at the end of the development period should we fail to meet the linear footage requirements and certain production requirements have not been satisfied. We currently expect to satisfy these requirements and have recognized no liability related to non-performance.

4. ALLIANCE ACQUISITION

In August 2008, Quicksilver completed the Alliance Acquisition, under which we acquired leasehold, royalty and midstream assets in the Barnett Shale in northern Tarrant and southern Denton counties of Texas. The purchase price was determined as follows:

(In thousands)	
Purchase Price:	
Cash paid	$ 1,000,000
Cash received from post-closing settlement	(9,086)
Cash paid for acquisition-related expenses	1,368
Total cash	992,282
Issuance of 10,400,468 common shares	262,092
	$ 1,254,374

Quicksilver's purchase price allocation is presented below:

(In thousands)	
Allocation of Purchase Price:	
Oil and gas properties – proved	$ 788,457
Oil and gas properties – unproved	440,372
Midstream assets	27,652
Liabilities assumed	(1,035)
Asset retirement obligations	(1,072)
	$ 1,254,374

We finalized the purchase price allocation during the quarter ended September 30, 2009.

Pro Forma Information

The following table reflects our unaudited consolidated pro forma statements of income as though the Alliance Acquisition, associated borrowings and issuance of Quicksilver common stock had occurred on January 1 for each year presented. The revenue and expenses for the acquisition are included in our 2008 consolidated results beginning from the date of closing. The pro forma information is not necessarily indicative of the results of operations that would have been achieved had the acquisition been effective at January 1 each year presented.

	For The Years Ended December 31,	
	2008	2007
	(In thousands, except per share data)	
Revenues	$ 875,607	$ 629,868
Net income (loss)	$ (384,645)	$ 428,314
Earnings (loss) per common share - basic	($2.29)	$2.57
Earnings (loss) per common share - diluted	($2.29)	$2.40

5. DIVESTITURE OF NORTHEAST OPERATIONS

In November 2007, we closed the BreitBurn Transaction, which resulted in the contribution of all of our oil and gas properties and facilities in our Northeast Operations to BBEP. Total consideration for the BreitBurn Transaction was $750 million of cash and 21.348 million common units of BBEP, equaling total consideration of $1.47 billion based on the BBEP unit closing price on the closing date. Under the terms of the transaction, we were required to retain 50% of the acquired units until May 1, 2009, but may now freely trade all of the acquired units.

Concurrent with closing the BreitBurn Transaction, we agreed to provide certain one-time benefits to 141 terminated employees, including settling unvested stock-based compensation in cash and providing cash severance and retention benefits payable in multiple installments over two years. Our total expense associated with the termination-related employee benefits was approximately $10.4 million which was recognized approximately 60% in 2007 and 20% in 2008 and 20% in 2009. The $6.3 million recognized in oil and gas production costs in the latter half of 2007 was comprised of expenses to settle unvested stock-based compensation of $4.9 million and severance payments of $1.4 million associated with services rendered through the end of 2007 by affected employees. The $2.1 million and $2.0 million recognized in 2008 and 2009, respectively, were attributable to the services rendered by the affected employees over these periods. Our expenses associated with the separation benefits ended on November 1, 2009.

A portion of our hedging program that was designated to the Northeast Operations for the period subsequent to the closing of the BreitBurn Transaction no longer qualified for hedge accounting treatment. Accordingly, concurrent with the completion of the BreitBurn Transaction, we reclassified the amounts included in accumulated other comprehensive income for the affected Northeast Operations hedges and recognized the changes in fair value for such contracts. This aggregate recognition totaled approximately $0.8 million, which increased other revenue in the 2007 consolidated statement of income. In the fourth quarter of 2007, we re-designated the hedges originally attributed to the Northeast Operations as hedges of other U.S. production and applied hedge accounting treatment for prospective changes in value.

In completing the BreitBurn Transaction, we utilized investment banking services. Approximately $2 million of expense related to such services was included in general and administrative expense during the third quarter of 2007, with an additional approximately $8.2 million recognized in the fourth quarter of 2007 as a reduction of proceeds generated by the BreitBurn Transaction.

Under GAAP, we held and continue to hold a "continuing interest" in the assets and subsidiaries sold in the BreitBurn Transaction as we owned approximately 32% of BBEP's outstanding common units following the BreitBurn Transaction. Thus, we deferred $294 million, or 32%, of the $923 million calculated book gain and recorded our investment in BBEP units, with an aggregate value of $724 million, net of the $294 million deferred gain for a net carrying value of $430 million at December 31, 2007. See Note 9 for more recent developments regarding our investment in BBEP.

Under the full cost method of accounting, our U.S. exploration and production assets are considered a single asset. The divestiture of the Northeast Operations, therefore, represented a fractional divestiture of a single asset which precludes reporting the Northeast Operations' financial position and results of operations as discontinued operations within the consolidated financial statements.

6. DERIVATIVES AND FAIR VALUE MEASUREMENTS

Commodity Price Derivatives

As of December 31, 2009, we had price collars hedging 200 MMcfd, 120 MMcfd and 60 MMcfd of our anticipated natural gas production for 2010, 2011 and 2012, respectively. We also had fixed price swaps hedging 10 MBbld and 5 MBbld of our anticipated 2010 and 2011 NGL production, respectively. 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, whereby we received $54.9 million. The settlement was recorded to AOCI and will be reclassified into natural gas revenue as we sell the associated hedged production volumes during 2010. Excluded from the amounts presented in the tables below are additional price collars and swaps entered into during 2010. In January 2010, we entered into a swap that fixed the Houston Ship Channel basis for 20 MMcfd of natural gas at a deduction of $0.09 per Mcf from NYMEX for February through December 2010. We also entered in a swap for three MBbld of our 2011 NGL fixing the price at $41.95 per Bbl.

Interest Rate Derivatives

In June 2009, we entered into interest rate swaps on our $475 million senior notes due 2010 and our $350 million senior subordinated notes effectively converting the interest on those issues from a fixed to a floating rate indexed to a one-month LIBOR. The maturity dates and all other significant terms are the same as those of the underlying debt. Under these swaps, we pay a variable interest rate and receive the fixed rate applicable to the underlying debt. The interest income or expense is accrued as earned and recorded as an adjustment to the interest expense accrued on the fixed-rate debt. The interest rate swaps are designated as fair value hedges of the underlying debt. The value of the contracts, excluding the net interest accrual, amounted to a net asset of $4.1 million as of December 31, 2009. The offsetting fair value adjustment to the debt hedged resulted in an increase of long-term debt by $4.1 million as of December 31, 2009. No ineffectiveness was recorded in connection with the fair value hedges. The average effective interest rates on the 2015 Senior Notes and Senior Subordinated Notes, since we entered into the hedges in June 2009, were approximately 5.1% and 3.7%, respectively.

In February 2010, we executed early settlement of our interest rate swaps. We received cash of $18.0 million in the settlement, which has been recorded as an adjustment to the carrying value of the debt and will be amortized to earnings over the life of the associated underlying debt instruments.

We subsequently entered into new interest rate swaps on our senior notes due 2015 and our senior subordinated notes that convert the interest paid on those issues from a fixed to a floating rate indexed to six-month LIBOR. The maturity dates and all other significant terms are the same as those of the underlying debt. As a result, these interest rate swaps qualified for hedge accounting treatment as fair value hedges.

Other Derivatives

Based on information available on June 19, 2009, we recognized a liability pursuant to the Gas Purchase Commitment based on the estimated production volumes attributable to Eni through December 31, 2010, which then totaled 22.2 Bcf. The Gas Purchase Commitment contains an embedded derivative that is adjusted to fair value throughout the period of the commitment, which expires on December 31, 2010. We recognized a $6.6 million increase in the fair value of the embedded derivative liability between June 19 and December 31, 2009 and recorded a valuation loss as a component of costs of purchased natural gas. At

December 31, 2009, we had a remaining liability of $50.7 million, including the $6.6 million liability for the embedded derivative. The following summarizes activity to the Gas Purchase Commitment:

(In thousands)	
Initial valuation of liability [1]	$ 58,294
Decrease due to gas volumes purchased	(14,175)
Embedded derivative increase (decrease) due to:	
Price changes	7,904
Volume changes	(1,279)
Total embedded derivative	6,625
Balance at December 31, 2009	$ 50,744

[1] Initial valuation of the Gas Purchase Commitment was estimated using estimated Eni production volumes from June 19, 2009 through December 2010 and published future market prices and risk-adjusted interest rates as of June 19, 2009.

The estimated fair value of our derivative instruments at December 31, 2008 and 2009 were as follows:

	Asset Derivatives As of December 31,		Liability Derivatives As of December 31,	
	2009	2008	2009	2008
	(In thousands)		(In thousands)	
Derivatives designated as hedges:				
Commodity contracts reported in:				
Current derivative assets	$ 97,883	$ 179,079	$ 638	$ 2,500
Noncurrent derivative assets	11,031	116,006	-	-
Current derivative liabilities	243	-	638	1,865
Interest rate contracts reported in:				
Current derivative assets	712	-	-	-
Noncurrent derivative assets	3,396	-	-	-
Total derivatives designated as hedges	$ 113,265	$ 295,085	$ 1,276	$ 4,365
Derivatives not designated as hedges:				
Gas Purchase Commitment reported in:				
Accrued liabilities	$ -	$ -	$ 6,625	$ -
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 hedges	$ -	$ -	$ 6,625	$ 12,902
Total derivatives	$ 113,265	$ 295,085	$ 7,901	$ 17,267

[1] During 2009, our net cash payments were $16.5 million, including derivative settlements, to complete our obligations under the Michigan Sales Contract.

The following table shows the level of inputs used in our fair value calculations of our derivative instruments at December 31, 2008 and 2009:

	Significant Other Observable Inputs - Level 2 at December 31,	
	2009	2008
	(In thousands)	
Derivatives		
Gas Purchase Commitment	$ (6,625)	$ -
Michigan Sales Contract	-	(8,063)
Commodity futures contracts	107,881	285,881
Interest rate contracts	4,108	-
Total derivatives-net	$ 105,364	$ 277,818

The decrease in carrying value of our commodity price derivatives since December 31, 2008 principally resulted from monthly settlements received during 2009 and the $54.9 million early settlement of a natural gas collar that hedged 2010 natural gas production. These decreases were partially offset by the overall decline in market prices for natural gas relative to the prices in our open derivative instruments at December 31, 2009.

The changes in the carrying value of our derivatives for 2009 and 2008 are presented below:

	For the Two Years Ended December 31, 2009				
	Michigan Contract	Gas Purchase Commitment [1]	Fair Value Derivatives	Cash Flow Derivatives	Total
			(In thousands)		
Derivative fair value at December 31, 2007	$ (63,777)	$ -	$ -	$ (5,505)	$ (69,282)
Change in amounts receivable/payable-net	3,518	-	-	(438)	3,080
Net settlements	48,284	-	-	-	48,284
Net settlements reported in revenue	-	-	-	18,392	18,392
Ineffectiveness reported in other revenue	(926)	-	-	2,547	1,621
Unrealized gains reported in OCI	-	-	-	275,723	275,723
Derivative fair value at December 31, 2008	$ (12,901)	$ -	$ -	$ 290,719	$ 277,818
Change in amounts receivable/payable-net	(3,518)	-	9,180	-	5,662
Net settlements	16,479	-	-	-	16,479
Net settlements reported in revenue	-	-	-	(310,868)	(310,868)
Net settlements reported in interest expense	-	-	13,724	-	13,724
Unrealized change in fair value of Gas Purchase Commitment reported in costs of purchased gas	-	(6,625)	-	-	(6,625)
Change in fair value of effective interest swaps	-	-	(18,796)	-	(18,796)
Ineffectiveness reported in other revenue	(60)	-	-	(71)	(131)
Cash settlement reported in OCI	-	-	-	(54,896)	(54,896)
Unrealized gains reported in OCI	-	-	-	182,997	182,997
Derivative fair value at December 31, 2009	$ -	$ (6,625)	$ 4,108	$ 107,881	$ 105,364

[1] Reported in accrued liabilities.

Gains and losses from the effective portion of derivative assets and liabilities held in AOCI expected to be reclassified into earnings over the next twelve months would result in a gain of $97.0 million net of income taxes. An additional $35.7 million, net of income taxes, will be reclassified from AOCI for the gain realized on the 2010 natural gas collar settled in March 2009. Hedge derivative ineffectiveness resulted in $0.1 million of net losses and $1.6 million and $1.0 million of net gains for the years ended December 31, 2009, 2008 and 2007, respectively.

7. ACCOUNTS RECEIVABLE

Accounts receivable consisted of the following:

	As of December 31,	
	2009	2008
	(In thousands)	
Accrued production receivables	$ 33,241	$ 47,552
Joint interest receivables	12,889	29,420
Interest rate swap settlement receivable	9,180	-
Income tax receivable	7,018	47,928
Accrued production taxes receivable	2,120	12,877
Other receivables	1,254	5,624
Allowance for doubtful accounts	(449)	(86)
	$ 65,253	$ 143,315

8. OTHER CURRENT ASSETS

Other current assets consisted of the following:

	As of December 31,	
	2009	2008
	(In thousands)	
Spare parts and supplies	$ 44,258	$ 64,185
Prepaid production taxes	5,071	7,239
Prepaid drilling rentals	-	384
Deposits	2,758	1,680
Other prepaid expenses	2,856	1,945
	$ 54,943	$ 75,433

9. INVESTMENT IN BREITBURN ENERGY PARTNERS L.P.

In 2007, we received common units of BBEP, a publicly traded limited partnership, as part of the BreitBurn Transaction, which is more fully described in Note 5 to these consolidated financial statements. 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%. At December 31, 2009, we held an ownership interest in BBEP of approximately 40% by virtue of employee and director stock-based compensation programs at BBEP.

During the first quarter of 2009 and fourth quarter of 2008, we evaluated our investment in BBEP for impairment in response to decreases in both prevailing commodity prices and BBEP's unit price. We considered numerous factors in evaluating whether this decline was other-than-temporary. As a result of the period during which BBEP common units traded below our net carrying value per unit, prevailing petroleum prices and broad limitations on available capital resulted in the determination that the decline in value was other-than-temporary. Accordingly, the impairment analysis at December 31, 2008 utilized a price of $7.05 per BBEP unit, or an aggregate fair value of $150.5 million for our investment in BBEP. The estimated fair value of $150.5 million was then compared to our carrying value of $470.9 million. The difference of $320.4 million was recognized as an impairment charge during 2008.

At March 31, 2009, an additional charge for impairment of $102.1 million was recognized as the closing unit price of $6.53 per BBEP unit, or an aggregate fair value of $139.4 million exceeded our carrying value of $241.5 million. No subsequent impairment of our investment occurred as the December 31, 2009 closing price of $10.59 per BBEP exceeded our carrying value of $5.28 per unit. Additional impairment of our investment in BBEP could occur in the future depending upon the performance of BBEP's unit price, which itself is dependent upon numerous factors.

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 Twelve Months Ended September 30,2009	For the Eleven Months Ended September 30, 2008
	(In thousands)	
Revenue [1]	$ 534,192	$ 420,321
Operating expense [2]	307,391	251,618
Operating income	226,801	168,703
Interest and other [3]	37,458	27,795
Income tax (benefit) expense	336	593
Noncontrolling interests	15	206
Net income available to BBEP	$ 188,992	$ 140,109
Net income available to common unitholders	$ 188,992	$ 141,660

(1) Unrealized gains on commodity derivatives of $193.5 million and $39.4 million were included for the twelve months ended September 30, 2009 and eleven months ended September 30, 2008, respectively. Realized gains on commodity derivatives of $70.6 million for the early settlement of derivative positions were included for the twelve months ended September 30, 2009.

(2) An impairment of BBEP's oil and gas properties of $86.4 million was included for the twelve months ended September 30, 2009.

(3) The twelve months ended September 30, 2009 included $11.1 million for unrealized losses on interest rate swaps and the eleven months ended September 30, 2008 included $2.3 million for unrealized losses on interest rate swaps.

	As of September 30, 2009	As of December 31, 2008
	(In thousands)	
Current assets	$ 121,207	$ 140,566
Property, plant and equipment	1,754,174	1,840,341
Other assets	114,673	235,927
Current liabilities	64,573	79,990
Long-term debt	585,000	736,000
Other non-current liabilities	72,519	47,413
Partners' equity	1,267,962	1,353,431

Changes in the balance of our investment in BBEP for 2009 and 2008 were as follows:

	As of December 31, 2009	As of December 31, 2008
	(In thousands)	
Beginning investment balance	$ 150,503	$ 420,171
Equity income in BBEP	75,444	93,298
Distributions from BBEP	(11,100)	(42,579)
Non-cash impairment of BBEP	(102,084)	(320,387)
Ending investment balance	$ 112,763	$ 150,503

Item 15 in this Annual Report contains BBEP's financial statements, which have been included pursuant to SEC Rule 3-09.

10. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consisted of the following:

	As of December 31, 2009	As of December 31, 2008
	(In thousands)	
Oil and gas properties		
Subject to depletion	$ 3,947,676	$ 3,621,831
Unevaluated costs	458,037	543,533
Accumulated depletion	(2,067,469)	(1,022,756)
Net oil and gas properties	2,338,244	3,142,608
Other plant and equipment		
Pipelines and processing facilities	779,493	533,234
General properties	68,698	57,941
Construction in progress	5,630	130,878
Accumulated depreciation	(106,125)	(66,946)
Net other property and equipment	747,696	655,107
Property, plant and equipment, net of accumulated depletion and depreciation	$ 3,085,940	$ 3,797,715

Ceiling Test Analysis and Impairment

As described in Note 2, we are required to perform a quarterly ceiling test for impairment of our oil and gas properties in each of our cost centers. Due to significant decreases in natural gas and NGL market prices, we have recognized charges for impairment of both our U.S. and Canadian cost centers during 2009 and 2008.

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 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 an AECO 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.

The second quarter 2009 ceiling test for our U.S. oil and gas properties resulted in no further recognition of impairment due principally to price recoveries during the second quarter; however, the second quarter ceiling test for our Canadian oil and gas properties resulted in an additional charge for impairment. We computed the 2009 second quarter Canadian ceiling amount using an AECO benchmark price of $2.87 per Mcf. The carrying value of our Canadian oil and gas reserves exceeded the present value of our Canadian proved reserves at June 30, 2009 by $70.6 million (pre-tax), which we recorded as an impairment charge in the second quarter of 2009.

At September 30, 2009, the unamortized cost of our Canadian oil and gas properties exceeded the full cost ceiling limitation by approximately $38.8 million (pre-tax). The full cost ceiling limitation included $25.7 million (pre-tax) for hedge valuations. We computed the 2009 third quarter ceiling using an AECO price of $3.41 per Mcf. As permitted by GAAP then in effect, improvements in AECO spot natural gas prices subsequent to September 30, 2009 eliminated the necessity to record a charge for impairment. Our U.S. ceiling test for the third quarter of 2009 required no recognition of impairment of our U.S. oil and gas properties.

The fourth quarter 2009 Canadian ceiling test was based upon our December 31, 2009 Canadian proved reserves that were estimated using an AECO price of $3.76 per Mcf (the unweighted average of the preceding 12-month first-day-of-the-month prices). We used the present value of future net cash flows of our Canadian proved reserves discounted at 10% at December 31, 2009 and $48.2 million (pre-tax) for hedge valuations to determine the Canadian ceiling limit. The carrying value of our Canadian oil and gas properties exceeded the ceiling limit by $12.4 million (pre-tax), which we recorded as an impairment charge in the fourth quarter of 2009. The fourth quarter 2009 ceiling test for our U.S. oil and gas properties required no recognition of impairment.

In arriving at the ceiling amount for the fourth quarter of 2008, we used $5.71 per Mcf of natural gas, $44.60 per Bbl of oil and $21.65 per Bbl of NGL for our U.S. properties' production horizon. When the present value of our U.S. reserves was calculated, the carrying value exceeded the ceiling limit and resulted in a pre-tax charge for impairment of $624.3 million recognized during the fourth quarter of 2008. Our Canadian ceiling test for the fourth quarter of 2008 resulted in no impairment of our Canadian oil and gas properties.

The charges for ceiling test impairment recorded in 2009 and 2008 are summarized below:

	Net Capitalized Costs[1]	Ceiling Limitation[2]	Pre-tax Charge for Impairment
		(In thousands)	
First Quarter 2009			
United States	$ 2,727,130	$ 1,940,263	$ 786,867
Canada	458,135	348,519	109,616
Total	$ 3,185,265	$ 2,288,782	$ 896,483
Second Quarter 2009			
Canada	$ 400,696	$ 330,053	$ 70,643
Fourth Quarter 2009			
Canada	$ 385,931	$ 373,517	$ 12,414
2009 Consolidated charge for impairment			$ 979,540

	Net Capitalized Costs[1]	Ceiling Limitation[2]	Pre-tax Charge for Impairment
		(In thousands)	
Fourth Quarter 2008			
United States	$ 3,016,147	$ 2,391,832	$ 624,315

(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.

(2) The cost center ceiling is defined as the sum of (1) estimated future net revenue, discounted at 10% per annum, from proved reserves, based on the unweighted average of the preceding 12-month first day-of the-month prices (end of year prices for 2008 and 2007) adjusted to reflect local differentials and contract provisions, unescalated year-end costs and financial derivatives that hedge the our oil and gas revenue, (2) the cost of properties not being amortized, (3) the lower of cost or market value of unproved properties included in the cost being amortized less (4) income tax effects related to differences between the book and tax bases of the oil and gas properties.

In the fourth quarter of 2008, we determined that the exploration costs for the Delaware Basin of West Texas would become part of the U.S. full-cost pool and no longer remain excluded from depletion. As a result, we also evaluated our midstream assets in West Texas for impairment, recording an impairment charge of $9.2 million (pre-tax) to reduce those midstream assets to their estimated fair values.

Because of the volatility of oil and natural gas prices, no assurance can be given that we will not experience a charge for impairment in future periods.

Unevaluated Natural Gas and Oil Properties Not Subject to Depletion

Under full cost accounting, we may exclude certain unevaluated property costs from the amortization base pending determination of whether proved reserves have been discovered or impairment has occurred.. A summary of the unevaluated properties not subject to depletion at December 31, 2009 and 2008 and the year in which they were incurred follows:

	December 31, 2009 Costs Incurred During					December 31, 2008 Costs Incurred During				
	2009	2008	2007	Prior	Total	2008	2007	2006	Prior	Total
	(In thousands)					(In thousands)				
Acquisition costs	$ 12,463	$ 275,409	$ 54,855	$ 63,089	$ 405,816	$ 381,203	$ 54,094	$ 31,328	$ 53,998	$ 520,623
Exploration costs	29,029	16,470	–	–	45,499	19,632	–	–	–	19,632
Capitalized interest	3,985	2,737	–	–	6,722	3,278	–	–	–	3,278
Total	$ 45,477	$ 294,616	$ 54,855	$ 63,089	$ 458,037	$ 404,113	$ 54,094	$ 31,328	$ 53,998	$ 543,533

The following table summarizes the unevaluated property costs not subject to depletion.

	As of December 31,	
	2009	2008
	(In thousands)	
Fort Worth Basin	$ 312,892	$ 440,144
Canadian Horn River Basin	117,330	80,590
Green River Basin	27,131	18,580
Other	684	4,219
Total	$ 458,037	$ 543,533

Costs are transferred into the amortization base on an ongoing basis, as projects are evaluated and proved reserves established or impairment determined. Pending determination of proved reserves attributable to the above costs; we cannot assess the future impact on the amortization rate. Unevaluated acquisition costs will require an estimated eight to ten years of exploration and development activity before evaluation is complete.

Other Matters

Capitalized overhead costs that directly relate to exploration and development activities were $17.1 million, $16.8 million and $7.0 million for 2009, 2008 and 2007, respectively. Depletion per Mcfe was $1.36, $1.68 and $1.28 for 2009, 2008 and 2007, respectively.

11. OTHER ASSETS

Other assets consisted of the following:

	As of December 31,	
	2009	2008
	(In thousands)	
Deferred financing costs	$ 60,114	$ 46,375
Less accumulated amortization	(14,249)	(9,507)
Net deferred financing costs	45,865	36,868
Deposits	–	3,008
Other	898	772
	$ 46,763	$ 40,648

Costs related to the acquisition of debt are deferred and amortized over the term of the debt.

12. ACCRUED LIABILITIES

Accrued liabilities consisted of the following:

	As of December 31,	
	2009	2008
	(In thousands)	
Gas Purchase Commitment liability	$ 50,744	$ –
Interest payable	71,768	30,713
Accrued operating expenses	21,136	20,296
Prepayments from partners	5,224	974
Revenue payable	4,141	7,181
Accrued production and property taxes	2,157	4,137
Environmental liabilities	659	50
Accrued product purchases	483	1,382
Accrued capital expenditures	–	1,695
Other	292	535
	$ 156,604	$ 66,963

13. LONG-TERM DEBT

Long-term debt consisted of the following:

	As of December 31, 2009	As of December 31, 2008
	(In thousands)	
Senior Secured Credit Facility	$ 467,569	$ 827,868
Senior notes due 2015, net of unamortized discount of $5,036 and $5,938	469,964	469,062
Senior notes due 2016, net of unamortized discount of $18,641 and $-	581,359	–
Senior notes due 2019, net of unamortized discount of $6,996 and $-	293,004	–
Senior subordinated notes due 2016	350,000	350,000
Convertible debentures, net of unamortized discount of $13,881 and $20,761	136,119	129,239
KGS Credit Agreement	125,400	174,900
Senior secured second lien facility, net of unamortized discount of $- and $13,050	–	641,555
Total debt	2,423,415	2,592,624
Fair value of interest rate swaps — hedges	4,108	–
Less current maturities	–	(6,579)
Long-term debt	$ 2,427,523	$ 2,586,045

Maturities are as follows:

	Total Indebtedness	Senior Secured Credit Facility	Senior Notes due in 2015	Senior Notes due in 2016	Senior Notes due in 2019	Senior Subordinated Notes	Convertible Debentures	KGS Credit Agreement
				(In thousands)				
2010	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –
2011	–	–	–	–	–	–	–	–
2012	592,969	467,569	–	–	–	–	–	125,400
2013	–	–	–	–	–	–	–	–
2014	–	–	–	–	–	–	–	–
Thereafter	1,875,000	–	475,000	600,000	300,000	350,000	150,000	–
	$ 2,467,969	$ 467,569	$ 475,000	$ 600,000	$ 300,000	$ 350,000	$ 150,000	$ 125,400

Senior Secured Credit Facility

Our Senior Secured Credit Facility matures on February 9, 2012. The borrowing base at December 31, 2009 was $1.0 billion, which resulted from a redetermination in October 2009. The Senior Secured Credit Facility provides us an option to increase the commitment by up to $250 million, with a maximum of $1.45 billion with lender consents and additional commitments. We can also extend the facility up to two additional years with lenders' approval. The facility provides for revolving loans, swingline loans and letters of credit from time to time in an aggregate amount not to exceed the borrowing base which is calculated based on several factors. U.S. borrowings under the facility are secured by, among other things, Quicksilver's and our U.S. subsidiaries' oil and gas properties. Canadian borrowings under the facility are secured by, among other things, all of our oil and gas properties. We also pledged our equity interests in BBEP to secure our obligations under the Senior Secured Credit Facility. At December 31, 2009, there was approximately $498 million available under the facility. In January 2010, we repaid $95 million of borrowings outstanding under the Senior Secured Credit Facility using the proceeds from the sale of the Alliance Midstream Assets to KGS. Our ability to remain in compliance with the financial covenants in our credit facility may be affected by events beyond our control, including market prices for our products. Any future inability to comply with these covenants, unless waived by the requisite lenders, could adversely affect our liquidity by rendering us unable to borrow further under our credit facilities and by accelerating the maturity of our indebtedness.

Senior Notes Due 2015

On June 27, 2008, we issued $475 million of senior notes due 2015, which are unsecured, senior obligations of Quicksilver. Interest at the rate of 8.25% is payable semiannually on February 1 and August 1.

Senior Notes Due 2016

On June 25, 2009, we issued $600 million of senior notes due 2016, which are unsecured, senior obligations of Quicksilver. The notes were issued at 96.717% of par, which resulted in proceeds of $580.3 million that were used to repay a portion of the Senior Secured Second Lien Facility. Interest at the rate of 11.75% is payable semiannually on January 1 and July 1.

Senior Notes Due 2019

On August 14, 2009, we issued $300 million of senior notes due 2019, which are unsecured, senior obligations of Quicksilver. The notes were issued at 97.612% of par, which resulted in proceeds of $292.8 million that were used to repay a portion of our Senior Secured Credit Facility. Interest at the rate of 9.125% is payable semiannually on February 15 and August 15.

Senior Secured Second Lien Facility

On August 8, 2008, we entered into a $700 million five-year Senior Secured Second Lien Facility pursuant to the Alliance Acquisition. During 2009, proceeds from the Eni Transaction and Senior Notes Due 2016 were used to fully repay and terminate the remaining indebtedness under our Senior Secured Second Lien Facility. Upon termination of the Senior Secured Second Lien Facility, Quicksilver's and its domestic subsidiaries' guarantee obligations, which were secured by a second lien on substantially all the assets of Quicksilver and its domestic subsidiaries, terminated. Furthermore, the financial covenants which required a minimum value of the cash flows of our oil and gas reserves under our Senior Secured Credit Facility were also eliminated.

Senior Subordinated Notes

Our senior subordinated notes due 2016 were issued in 2006. The senior subordinated notes are unsecured, senior subordinated obligations of Quicksilver and bear interest at the rate of 7.125% which is payable semiannually on April 1 and October 1.

Convertible Debentures

The convertible debentures due November 1, 2024 are contingently convertible into shares of Quicksilver common stock. The debentures bear interest at an annual rate of 1.875% payable semi-annually on May 1 and November 1. Additionally, holders of the debentures can require us to repurchase all or a portion of their debentures on November 1, 2011, 2014 or 2019 at a price equal to the principal amount thereof plus accrued and unpaid interest. The debentures are convertible into Quicksilver common stock at a rate of 65.4418 shares for each $1,000 debenture, subject to adjustment. Generally, except upon the occurrence of specified events, holders of the debentures are not entitled to exercise their conversion rights unless the closing price of Quicksilver's stock price is at least $18.34 (120% of the conversion price per share) for at least 20 trading days during the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter. 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 January 1, 2010, the debentures were not convertible based on share prices for the quarter ended December 31, 2009.

KGS Credit Agreement

Concurrent with its IPO, KGS entered into the KGS Credit Agreement that matures August 12, 2012. The KGS Credit Agreement may be extended through an option exercisable by KGS to extend the agreement for up to two additional years with lenders' approval. In October 2009, the lenders increased their commitment under agreement to $320 million. With additional lender consent and commitment increases, KGS' availability could expand to $350 million. KGS must maintain certain financial ratios that can limit its borrowing capacity. Borrowings under the agreement are guaranteed by KGS' subsidiaries and are secured by substantially all of the assets of KGS and each of its subsidiaries. KGS received $11.1 million in proceeds from the underwriters' January 2010 exercise of their option to purchase an additional 549,200 units. These proceeds were used by KGS to repay $11 million of borrowings outstanding under the KGS Credit Agreement. KGS also re-borrowed $95 million from the KGS Credit Agreement to complete KGS' purchase of our Alliance Midstream Assets.

Summary of All Outstanding Debt

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

	Priority on Collateral and Structural Seniority (1)						*Recourse only to KGS assets*
	Highest priority ←					**→ Lowest priority**	
		Equal priority					
	Senior Secured Credit Facility	**2015 Senior Notes**	**2016 Senior Notes**	**2019 Senior Notes**	**Senior Subordinated Notes**	**Convertible Debentures**	**KGS Credit Agreement**
Scheduled maturity date	February 9, 2012	August 1, 2015	January 1, 2016	September 1, 2019	April 1, 2016	November 1, 2024	August 10, 2012
Interest rate at December 31, 2009 (2)	3.30%	8.25%	11.75%	9.125%	7.125%	1.875%	3.26%
Base interest rate options (3)	LIBOR, ABR or specified(4)	N/A	N/A	N/A	N/A	N/A	LIBOR, ABR or specified(5)
Financial covenants (6)	- Minimum current ratio of 1.0 - Minimum EBITDA to interest expense ratio of 2.5	N/A	N/A	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 (6)	- 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	- 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 (7)	$467.6 million	$486.9 million	$681.0 million	$313.8 million	$326.4 million	$180.0 million	$125.4 million

(1) The Senior Secured Credit Facility is secured by a first perfected lien on substantially all our assets excluding KGS' assets. The other debt presented is based upon structural seniority and priority of payment.

(2) Represents the weighted average borrowing rate payable to lenders and excludes effects of interest rate derivatives.

(3) Interest rate options include a base rate plus a spread.

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

(5) The KGS Credit Agreement was amended in October 2009 to add a floor to ABR of one-month LIBOR plus a 1%, increase in the ABR margin to a range of 2.00% to 3.00% and an increase in the Eurodollar and specified rate margins to a range of 3.00% to 4.00%.

(6) 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.

(7) 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.

14. ASSET RETIREMENT OBLIGATIONS

The following table provides a reconciliation of the changes in the estimated asset retirement obligation from January 1, 2008 through December 31, 2009.

	As of December 31,	
	2009	2008
	(In thousands)	
Beginning asset retirement obligations	$ 35,193	$ 24,510
Additional liability incurred	6,567	8,231
Change in estimates	12,916	4,288
Accretion expense	2,325	1,483
Sale of properties	(380)	-
Asset retirement costs incurred	(379)	(359)
Gain on settlement of liability	131	119
Currency translation adjustment	3,004	(3,079)
Ending asset retirement obligations	59,377	35,193
Less current portion	(109)	(440)
Non-current asset retirement obligation	$ 59,268	$ 34,753

15. INCOME TAXES

Our current and deferred tax positions were significantly impacted by the November 2007 divestiture of the Northeast Operations and the resulting gain and the impairments of our oil and gas properties and our investment in BBEP in 2009 and 2008. Significant components of our deferred tax assets and liabilities as of December 31, 2009 and 2008 are as follows:

	As of December 31,	
	2009	2008
	(In thousands)	
Deferred tax assets:		
Net operating loss carry forwards	$ 290,894	$ 176,957
Cash flow hedge settlements	19,214	-
Deferred compensation expense	10,654	4,236
Other	8,712	969
Deferred tax assets	329,474	182,162
Deferred tax liabilities:		
Property, plant and equipment	$ (186,658)	$ (318,070)
Cash flow hedge gains	(55,372)	(92,854)
BBEP investment	(29,398)	(40,270)
Convertible debenture interest	(18,588)	(17,297)
Deferred tax liabilities	(290,016)	(468,941)
Total deferred tax asset (liability)	$ 39,458	$ (286,779)
Reflected in the consolidated balance sheets as:		
Non-current deferred income tax asset	$ 133,051	$ -
Current deferred income tax liability	(51,675)	(52,393)
Non-current deferred income tax liability	(41,918)	(234,386)
	$ 39,458	$ (286,779)

The 2008 presentation of deferred tax assets and liabilities has been conformed to the 2009 presentation. In conforming the 2008 amounts, we now present a deferred tax liability for our investment in BBEP by combining $112 million previously reported as deferred tax asset captioned as "BBEP impairment" and $152 million previously reported as a deferred tax liability attributable to "property, plant and equipment."

Tax rate reductions were enacted during 2007 by the Canadian federal government and by Alberta provincial government. Our Canadian deferred income tax balances were revalued to reflect the changes in these tax rates. We recorded $4.9 million of income tax benefits in 2007 as a result of the enactment of Canadian rate reductions. No further rate changes occurred in 2008 or 2009.

The components of income tax expense for 2009, 2008 and 2007 are as follows:

	2009	2008	2007
		(In thousands)	
Current state income tax expense (benefit)	$ (2)	$ (4)	$ 1,143
Current U.S. federal income tax expense (benefit)	(202)	(45,210)	45,394
Current Canadian income tax expense	-	199	28
Total current income tax expense (benefit)	(204)	(45,015)	46,565
Deferred state income tax expense (benefit)	(4,928)	1,939	2,538
Deferred U.S. federal income tax expense (benefit)	(262,217)	(190,938)	194,129
Deferred Canadian income tax expense (benefit)	(24,268)	22,559	11,129
Total deferred income tax expense (benefit)	(291,413)	(166,440)	207,796
Total income tax expense (benefit)	$ (291,617)	$ (211,455)	$ 254,361

The following table reconciles the statutory federal income tax rate to the effective tax rate for 2009, 2008 and 2007:

	2009	2008	2007
U.S. federal statutory tax rate	35.00%	35.00%	35.00%
Permanent differences	(0.18)%	(0.33)%	0.01%
Noncontrolling interest benefit	0.71%	-	-
State income taxes net of federal deduction	0.38%	(0.22)%	0.33%
Recognition of uncertain tax position	-	(0.09)%	1.18%
Foreign income taxes	(0.98)%	1.38%	(1.71)%
Other	(0.08)%	0.40%	-
Effective income tax rate	34.85%	36.14%	34.81%

We incurred net operating tax losses of $331 million and $656 million in 2009 and 2008, respectively. Approximately $138 million of this loss was carried back to 2007. The remaining $849 million is included in deferred tax assets at December 31, 2009. Our net operating losses will expire in 2028 and 2029. In December 2009, newly enacted federal legislation allowed us to carry back 2008 alternative minimum tax losses of $35 million to 2004 and 2007. The net operating losses were not reduced by a valuation allowance, because management believes that future taxable income would more likely than not be sufficient to utilize substantially all of our operating loss tax carry forwards prior to their expiration.

During 2007, we recognized $2.8 million in income tax benefits associated with the exercise of employee stock options as an increase to additional paid in capital. No such income tax benefits were recognized in 2008 and 2009 because of the availability of net operating loss tax carry forwards of Quicksilver.

The following schedule reconciles the total amounts of unrecognized tax benefits for 2009 and 2008.

	As of December 31, 2009	As of December 31, 2008
	(In thousands)	
Beginning unrecognized tax benefits	$ 9,255	$ 9,997
Gross amounts of increases in unrecognized tax benefits as a result of tax positions taken during a prior period	-	834
Amount of decreases in unrecognized tax benefits related to settlements with taxing authorities	-	(1,301)
Gross amounts of decreases in unrecognized tax benefits as a result of tax positions taken during the current year	(36)	-
Reductions resulting from the lapse of applicable statutes of limitations	-	(275)
Unrecognized tax benefits	$ 9,219	$ 9,255

Approximately $8.9 million of these unrecognized tax benefits at December 31, 2009 if recognized, would impact the effective tax rate. Interest and penalties of $0.6 million related to unrecognized tax benefits were recognized as interest expense for 2007 and subsequently reversed in 2008. An audit was completed by the IRS for 2004 and the statute of limitations has now expired for that year. During October 2009, the Internal Revenue Service commenced an audit of our 2007 and 2008 consolidated U.S. federal income tax returns. Although no significant adjustments are expected, any required adjustments will be made upon completion of the audit. We remain subject to examination by the Internal Revenue Service for the years 2001 through 2008 except for 2004. Our management does not expect that the total amounts of unrecognized tax benefits will significantly increase or decrease over the next twelve months.

16. COMMITMENTS AND CONTINGENCIES

Contractual Obligations.

Information regarding our contractual obligations, at December 31, 2009, is set forth in the following table.

	Transportation and Processing Contracts [1]	Drilling Rig Contracts [2]	Operating Leases [3]	Purchase Obligations [4]
	(In thousands)			
2010	$ 43,909	$ 45,519	$ 2,678	$ 19,554
2011	56,356	32,420	2,271	5,273
2012	80,905	17,876	1,363	-
2013	101,121	791	640	-
2014	79,391	-	558	-
Thereafter	267,434	-	418	-
Total	$ 629,116	$ 96,606	$ 7,928	$ 24,827

(1) Under contracts with various pipeline companies, we are obligated to provide minimum daily natural gas volumes for transport or processing, as calculated on a monthly basis, or pay for any deficiencies at a specified reservation fee rate. Our available production committed to the pipelines and processing plants is expected to meet, or exceed, the daily volumes required under the contracts.

(2) We lease drilling rigs from third parties for use in our development and exploration programs. The outstanding drilling rig contracts require payment of a specified day rate ranging from $20,500 to $26,500 for the entire lease term regardless of our utilization of the drilling rigs.

(3) We lease office buildings and other property under operating leases. Rent expense for operating leases with terms exceeding one month was $4.1 million in 2009, $5.0 million in 2008 and $5.2 million in 2007.

(4) At December 31, 2009, we and KGS were under contract to purchase goods and services related to field operations and gas processing plant operations. KGS obligations totaled $7.4 million.

Commitments

We had $39.1 million in surety bonds issued to fulfill contractual, legal or regulatory requirements and $34.5 million in letters of credit outstanding against the credit facility, including $21.4 million issued to provide credit support for surety bonds. Surety bonds and letters of credit generally have an annual renewal option.

Contingencies

On November 7, 2001, we filed a lawsuit against CMS Marketing Services and Trading Company ("CMS") in Texas. The suit alleged that CMS committed fraud when it entered into a 10-year contract with the Company on March 1, 1999 for the purchase and sale of 10,000 MMBtud of natural gas at a minimum price of $2.47 per MMBtu and breached the contract afterward by failing to comply with a provision of the contract requiring that, if the gas could be scheduled or delivered to derive additional value, the parties would share equally in the additional revenue. On May 15, 2007, the district court entered a final judgment in favor of Quicksilver against CMS, declaring our contract with CMS to be void and rescinded as of that date. CMS appealed this judgment. We also appealed seeking to have the contract voided from its inception and to recover jury-awarded punitive damages of $10 million. On June 25, 2009, the Court of Appeals for the Second District of Texas, reversed the original district court judgment. Pursuant to a settlement agreement, we paid CMS $5 million that was recognized as a component of general and administrative expense during 2009.

Our lawsuit filed October 13, 2006 against Eagle Drilling LLC ("Eagle") as well as Eagle Domestic Drilling LLC and its parent Blast Energy Services Inc. ("Eagle/Blast"), regarding three contracts for drilling rigs, is currently pending in U.S. District Court for the Southern District of Texas in Houston, Texas. We assert claims against Eagle for, among other things, breach of contract, breach of express and implied warranties, fraud, and negligence in connection with Eagle's obligation to provide three drilling rigs. We also seek declaratory relief, actual damages, and recovery of our attorney fees. Eagle/Blast are no longer parties in this case. In September 2008, we entered into a settlement agreement with Eagle/Blast that was approved in the court in October 2008. Under the settlement agreement, we agreed to pay Eagle/Blast $10 million over a three-year period, including $5 million on the settlement date. We recorded a $9.6 million charge to general and administrative expense during 2008 for the net present value of these payments. In the still pending suit, Eagle filed counter claims against us and our Executive Vice President – Operations, our Chairman, and our Chief Executive Officer for, among other things, alleged breach of contract, bad faith breach of contract, tortious interference with business relationships, false representation, conspiracy and invasion of privacy. Eagle's current complaint seeks an unspecified amount of actual and exemplary damages, interest, costs, and attorney fees. We are asserting a vigorous defense to Eagle's claims in addition to actively prosecuting our claims.

On September 17, 2007, Eagle and Rod and Richard Thornton, sued Quicksilver and our Executive Vice President – Operations, in state district court Cleveland County, Oklahoma for approximately $29 million in damages and an unspecified amount of punitive damages resulting from Quicksilver's repudiation of three rig contracts. In October 2009, a jury awarded $22 million to the plaintiffs. We are actively seeking an appeal in this matter.

On October 31, 2008, we filed a lawsuit in the 48th State District Court in Fort Worth, Texas against BBEP, certain entities related to BBEP, Provident Energy Trust ("Provident") and certain individuals who serve as, or have previously served as, directors or officers of these entities for violations of, among other things, breach of contract, the Texas Securities Act, the Texas Business & Commerce Code, common law fraud, fraudulent inducement, negligent misrepresentation and civil conspiracy. We sought relief for actual and exemplary damages, and for injunctive and declaratory relief. On February 3, 2010, the parties entered into a settlement agreement whereby we will receive $18 million in cash along with the retention of full voting rights for our units held in BBEP subject to the provisions of a limited standstill agreement, the ability to name two directors to the board of BBEP's general partner, the reinstitution of the BBEP quarterly distributions and other governance accommodations.

Environmental Compliance

Our operations are subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, we are subject to laws and regulations at the federal, state, provincial and local levels that relate to air and water quality, hazardous and solid waste management and disposal and other environmental matters. The cost of planning, designing, constructing and operating our facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures. At December 31, 2009, we had recorded $0.7 million for liabilities for environmental matters.

17. NONCONTROLLING INTERESTS AND KGS

KGS issued 4,000,000 newly issued common units on December 16, 2009 in the KGS Secondary Offering and received $80.3 million, net of underwriters' discount and other offering costs. The portion of these proceeds related to our initial ownership interests, $50.2 million, was recognized as an increase to "Additional Paid-in Capital" on our consolidated balance sheet. On January 4, 2010, the underwriters exercised their option to purchase an additional 549,200 newly issued common units for $11.1 million, which further reduced our ownership of KGS to 61.2% effective January 6, 2010. As a result we recognized an additional $6.7 million to "Additional Paid-in Capital" in January 2010. KGS offered additional units to the public to provide funding for its acquisition of the Alliance Midstream Assets from us, which was completed in January 2010 for $95.2 million.

As of December 31, 2009, KGS' ownership is summarized in the following table:

	KGS Ownership		
	Quicksilver	Third Parties	Total
General partner interests	1.7%	-	1.7%
Limited partner interests:			
Common interests	20.1%	37.5%	57.6%
Subordinated interests	40.7%	-	40.7%
Total interests	62.5%	37.5%	100.0%

The subordinated units will convert into an equal number of common units upon termination of the subordination period. The subordination period is expected to end in February 2011, assuming KGS continues to earn and pay at least $0.30 per quarter on each outstanding common unit through that time.

18. EARNINGS PER SHARE

The following is a reconciliation of the numerator and denominator used for the computation of basic and diluted net income per common share. Total per share amounts may not add due to rounding.

	Years Ended December 31,		
	2009	2008	2007
	(In thousands, except per share data)		
Net income (loss)	$ (557,473)	$ (378,276)	$ 475,390
Impact of assumed conversions – interest on 1.875% convertible debentures, net of income taxes	-	-	6,056
Income (loss) available to stockholders assuming conversion of convertible debentures	$ (557,473)	$ (378,276)	$ 481,446
Weighted average common shares – basic	169,004	162,004	156,517
Effect of dilutive securities [1]:			
Employee stock options	-	-	1,326
Employee stock awards	-	-	370
Contingently convertible debentures	-	-	9,816
Weighted average common shares – diluted	169,004	162,004	168,029
Earnings (loss) per common share – basic	$ (3.30)	$ (2.33)	$ 3.04
Earnings (loss) per common share – diluted	$ (3.30)	$ (2.33)	$ 2.87

(1) For 2009 and 2008, the effects of convertible debt of 9.8 million shares and stock options and unvested restricted stock units representing 0.8 million shares and 0.9 million, respectively were antidilutive and, therefore, excluded from the diluted share calculations. No outstanding options were excluded from the diluted net income per share calculation for the year ended December 31, 2007.

19. QUICKSILVER STOCKHOLDERS' EQUITY

Common Stock, Preferred Stock and Treasury Stock

We are authorized to issue 400 million shares of common stock with a par value per share of one cent and 10 million shares of preferred stock with a par value per share of one cent. At December 31, 2009, we had 169.8 million shares of common stock outstanding.

The following table shows common share and treasury share activity since January 1, 2007:

	Common Shares Issued	Treasury Shares Held
Opening balance at January 1, 2007	157,783,515	2,579,671
Stock options exercised	2,257,840	-
Restricted stock activity	591,915	37,055
Balance at December 31, 2008	160,633,270	2,616,726
Stock issuance	10,400,468	-
Stock repurchase	-	1,885,600
Stock options exercised	249,732	-
Restricted stock activity	459,229	70,469
Balance at December 31, 2008	171,742,699	4,572,795
Stock options exercised	610,000	-
Restricted stock activity	2,117,137	131,653
Balance at December 31, 2009	174,469,836	4,704,448

Quicksilver Stockholder Rights Plan

In 2003, our Board of Directors declared a dividend distribution of one preferred share purchase right for each outstanding share of common stock then outstanding. Each right, when it becomes exercisable, entitles stockholders to buy one one-thousandth of a share of Quicksilver's Series A Junior Participating Preferred Stock at an exercise price of $90, after adjustments to reflect the two-for-one stock split in January 2008.

The rights will be exercisable only if such a person or group acquires 15% or more of the common stock of Quicksilver or announces a tender offer the consummation of which would result in ownership by such a person or group (an "Acquiring Person") of 15% or more of the common stock of Quicksilver. This 15% threshold does not apply to certain members of the Darden family and affiliated entities, which collectively owned, directly or indirectly, approximately 30% of our common stock at December 31, 2009.

If an Acquiring Person acquires 15% or more of our outstanding common stock, each right will entitle its holder to purchase, at the right's then-current exercise price, a number of common shares of Quicksilver having a market value of twice such price. If Quicksilver is acquired in a merger or other business combination transaction after an Acquiring Person has acquired 15% or more of our outstanding common stock, each right will entitle its holder to purchase, at the right's then-current exercise price, a number of the acquiring company's common shares having a market value of twice such price.

Prior to the acquisition by an Acquiring Person of beneficial ownership of 15% or more of our common stock, the rights are redeemable for $0.01 per right at the option of our Board of Directors.

Stock-Based Compensation

2006 Equity Plan

In 2006, our Board of Directors and our shareholders approved the 2006 Equity Plan. Upon approval of the 2006 Equity Plan, 14 million shares of common stock were reserved for issuance as grants of stock options, appreciation rights, restricted shares, restricted stock units, performances shares, performance units and senior executive plan bonuses. On May 20, 2009, stockholders approved an amendment to the 2006 Equity Plan, which increased the number of shares available for issuance to 15 million. Our executive officers, other employees, consultants and non-employee directors are eligible to participate in the 2006 Equity Plan. Under the 2006 Equity Plan, options reflect an exercise price of no less than the fair market value on the date of grant and have a life of 10 years. At December 31, 2009 and 2008, 15.1 million shares and 12.2 million shares, respectively, (including 0.2 million shares and 0.1 million shares, respectively, surrendered to us to satisfy participants' tax withholding obligations which then became available for future issuance under the 2006 Equity Plan) of common stock were available for issuance as stock options, restricted stock and RSUs under the 2006 Equity Plan.

Stock Options

The following summarizes the values from and assumptions for the Black-Scholes option pricing model:

	2009	2008	2007
Wtd avg grant date fair value	$ 6.21	$ 13.67	N/A
Wtd avg grant date	Jan 2, 2009	Jan 2, 2008	N/A
Wtd avg risk-free interest rate	1.90%	3.41%	N/A
Expected life (in years)	6.0	6.0	N/A
Wtd avg volatility	56.76%	40.2%	N/A
Expected dividends	-	-	N/A

The following table summarizes our stock option activity for 2009:

	Shares	Wtd Avg Exercise Price	Wtd Avg Remaining Contractual Life	Aggregate Intrinsic Value
				(In thousands)
Outstanding at January 1, 2009	1,103,336	$ 14.20		
Granted	2,605,699	6.21		
Exercised	(610,000)	6.63		
Cancelled	(84,594)	8.84		
Outstanding at December 31, 2009	3,014,441	$ 8.97	8.5	$ 23,486
Exercisable at December 31, 2009	372,219	$ 13.98	5.4	$ 2,170

We estimate that a total of 2,945,350 stock options will become vested including those options already exercisable. These unexercised options have a weighted average exercise price of $9.04 and a weighted average remaining contractual life of 8.5 years.

Compensation expense related to stock options of $4.5 million, $1.6 million and $0.1 million was recognized for 2009, 2008 and 2007, respectively. Cash received from the exercise of stock options totaled $4.0 million, $1.2 million and $21.4 million for the years 2009, 2008 and 2007, respectively. The total intrinsic value of options exercised during 2009, 2008 and 2007, was $4.3 million, $6.7 million and $30.5 million, respectively.

Restricted Stock

The following table summarizes our restricted stock and stock unit activity for 2009:

	Payable in shares		**Payable in cash**	
	Shares	Wtd Avg Grant Date Fair Value	Shares	Wtd Avg Grant Date Fair Value
Outstanding at January 1, 2009	1,336,111	$ 24.01	-	$ -
Granted	2,279,679	6.28	339,835	6.22
Vested	(730,373)	22.20	-	-
Cancelled	(162,542)	14.12	(11,140)	6.22
Outstanding at December 31, 2009	2,722,875	$ 10.33	328,695	$ 6.22

At December 31, 2008, we had unvested compensation cost of $17.6 million. As of December 31, 2009, the unrecognized compensation cost related to outstanding unvested restricted stock was $15.1 million, which is expected to be recognized in expense over the next 2 years. Grants of restricted stock and stock units during 2009 had an estimated grant date fair value of $14.3 million. The fair value of RSUs settled in cash was $4.9 million at December 31, 2009. For 2009, 2008 and 2007, compensation expense of $14.6 million, $13.5 million and $11.0 million, respectively, was recognized. The total fair value of shares vested during 2009, 2008 and 2007 was $11.0 million, $15.1 million and $6.4 million, respectively.

KGS Restricted Phantom Units

Awards of phantom units have been granted under KGS' 2007 Equity Plan. On October 7, 2009, unitholders approved an amendment to the 2007 Equity Plan, which increased the number of units available for issuance to 750,000 as of November 4, 2009. All awards granted consist of phantom units that vest ratably over three years and are to be settled in common units or cash upon vesting as determined by the Board at the time of grant. At December 31, 2009 and 2008, 750,000 units and 603,993 units, respectively, were available for issuance under the KGS 2007 Equity Plan, as amended.

The following table summarizes information regarding the phantom unit activity:

	Payable in units		Payable in cash	
	Shares	Wtd Avg Grant Date Fair Value	Shares	Wtd Avg Grant Date Fair Value
Outstanding at January 1, 2009	139,918	$ 25.15	60,319	$ 21.63
Granted	(49,789)	25.25	(26,526)	13.79
Vested	405,428	10.06	5,420	16.65
Cancelled	(9,885)	15.90	(5,973)	21.36
Outstanding at December 31, 2009	485,672	$ 12.73	33,240	$ 27.12

At December 31, 2008, KGS had total unvested compensation cost of $2.3 million related to unvested phantom units. KGS recognized compensation expense for 2009 and 2008 of $2.6 million and $1.4 million, respectively. Grants of phantom units during the year ended December 31, 2009 had an estimated grant date fair value of $4.2 million. KGS has unearned compensation of $2.9 million which will be recognized in expense over the next 1.9 years. Phantom units that vested during 2009 and 2008 had a fair value of $1.6 million and $0.7 million, respectively.

20. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The following tables provide information about the entities that guarantee Quicksilver's senior notes and senior subordinated notes. The guarantees are full and unconditional and joint and several. Under SEC rules, we are required to present financial information segregated between its guarantor and non-guarantor subsidiaries. The indentures under both our senior notes and our senior subordinated notes distinguish between "restricted" subsidiaries and "unrestricted" subsidiaries and further specify supplemental information that is not required under GAAP. The following table illustrates our subsidiaries and their status pursuant to the senior notes due 2015, senior notes due 2016, senior notes due 2019 and the senior subordinated notes:

	Non-Guarantor Subsidiaries	
Guarantor Subsidiaries - Restricted	**Restricted**	**Unrestricted**
Cowtown Pipeline Funding, Inc.	Quicksilver Resources Canada, Inc.	Quicksilver Gas Services Holdings LLC
Cowtown Pipeline Management, Inc.	Mercury Michigan, Inc. [(1)]	Quicksilver Gas Services GP LLC
Cowtown Pipeline L.P.	Terra Energy Ltd. [(1)]	Quicksilver Gas Services LP
Cowtown Gas Processing L.P.	GTG Pipeline Corporation [(1)]	Quicksilver Gas Services Operating LLC [(4)]
	Terra Pipeline Company [(1)]	Quicksilver Gas Services Operating GP LLC [(4)]
	Beaver Creek Pipeline, LLC [(1)]	Cowtown Pipeline Partners L.P. [(4)]
	Quicksilver Resources Horn River Inc. [(2)]	Cowtown Gas Processing Partners L.P. [(4)]
	Cowtown Drilling Inc. [(3)]	

(1) Prior to the sale of our Northeast Operations in November 2007, these entities were restricted guarantor subsidiaries. After the sale, they have been reclassified to restricted non-guarantor subsidiaries for all periods presented.

(2) This entity was amalgamated into Quicksilver Resources Canada Inc. on January 1, 2009.

(3) This entity was dormant for the three-year period ended December 31, 2009.

(4) Each entity is a wholly owned subsidiary of and consolidated into KGS.

We own 100% of each of the restricted subsidiaries. Quicksilver and the restricted subsidiaries conduct all of our exploration and production activities, and the unrestricted subsidiaries only conduct midstream operations. Neither the restricted non-guarantor subsidiaries nor the unrestricted non-guarantor subsidiaries guarantee the obligations under the Senior Notes and the Senior Subordinated Notes. However, the restricted non-guarantor subsidiaries, like the restricted guarantor subsidiaries, are limited in their activity by the covenants in the indenture for such matters as:

- incurring additional indebtedness;
- paying dividends;
- selling assets;
- making investments; and
- making restricted payments.

Subject to restrictions set forth in the indentures, we may in the future designate one or more additional subsidiaries as unrestricted.

The following tables present financial information about Quicksilver and our restricted subsidiaries for the annual periods covered by the consolidated financial statements.

Condensed Consolidating Balance Sheets

	December 31, 2009							
	Quicksilver Resources Inc.	Restricted Guarantor Subsidiaries	Restricted Non-Guarantor Subsidiaries	Restricted Subsidiary Eliminations	Quicksilver and Restricted Subsidiaries	Unrestricted Non-Guarantor Subsidiaries	Consolidating Eliminations	Quicksilver Resources Inc. Consolidated
	(In thousands)							
ASSETS								
Current assets	$ 313,485	$ 394	$ 42,622	$ (121,580)	$ 234,921	$ 2,268	$ (17,251)	$ 219,938
Property and equipment	1,980,053	217,407	491,528	-	2,688,988	396,952	-	3,085,940
Investment in subsidiaries (equity method)	549,200	149,945	-	(436,437)	262,708	-	(149,945)	112,763
Other assets	235,304	-	3,112	-	238,416	9,067	(53,242)	194,241
Total assets	$ 3,078,042	$ 367,746	$ 537,262	$ (558,017)	$ 3,425,033	$ 408,287	$ (220,438)	$ 3,612,882
LIABILITIES AND EQUITY								
Current liabilities	$ 349,415	$ 120,302	$ 25,321	$ (121,580)	$ 373,458	$ 10,453	$ (17,251)	$ 366,660
Long-term liabilities	2,092,629	13,108	309,840	-	2,415,577	187,065	(53,242)	2,549,400
Quicksilver stockholders' equity	635,998	234,336	202,101	(436,437)	635,998	149,945	(149,945)	635,998
Noncontrolling interests	-	-	-	-	-	60,824	-	60,824
Total liabilities and equity	$ 3,078,042	$ 367,746	$ 537,262	$ (558,017)	$ 3,425,033	$ 408,287	$ (220,438)	$ 3,612,882

	December 31, 2008							
	Quicksilver Resources Inc.	Restricted Guarantor Subsidiaries	Restricted Non-Guarantor Subsidiaries	Restricted Subsidiary Eliminations	Quicksilver and Restricted Subsidiaries	Unrestricted Non-Guarantor Subsidiaries	Consolidating Eliminations	Quicksilver Resources Inc. Consolidated
	(In thousands)							
ASSETS								
Current assets	$ 424,862	$ 163	$ 102,384	$ (123,071)	$ 404,338	$ 2,439	$ (13,441)	$ 393,336
Property and equipment	2,756,915	1,774	550,906	-	3,309,595	432,272	55,848	3,797,715
Assets of discontinued operations	-	-	-	-	-	56,022	(56,022)	-
Investment in subsidiaries (equity method)	513,706	79,316	-	(363,203)	229,819	-	(79,316)	150,503
Other assets	206,099	123,298	910	-	330,307	1,916	(175,569)	156,654
Total assets	$ 3,901,582	$ 204,551	$ 654,200	$ (486,274)	$ 4,274,059	$ 492,649	$ (268,500)	$ 4,498,208
LIABILITIES AND EQUITY								
Current liabilities	$ 357,077	$ 122,677	$ 44,907	$ (123,071)	$ 401,590	$ 27,183	$ (10,274)	$ 418,499
Long-term liabilities	2,359,679	-	327,964	-	2,687,643	299,111	(118,608)	2,868,146
Liabilities of discontinued operations	-	-	-	-	-	60,302	(60,302)	-
Quicksilver stockholders' equity	1,184,826	81,874	281,329	(363,203)	1,184,826	79,316	(79,316)	1,184,826
Noncontrolling interests	-	-	-	-	-	26,737	-	26,737
Total liabilities and equity	$ 3,901,582	$ 204,551	$ 654,200	$ (486,274)	$ 4,274,059	$ 492,649	$ (268,500)	$ 4,498,208

Condensed Consolidating Statements of Income

For The Year Ended December 31, 2009

(In thousands)

	Quicksilver Resources Inc.	Restricted Guarantor Subsidiaries	Restricted Non-Guarantor Subsidiaries	Restricted Subsidiary Eliminations	Quicksilver and Restricted Subsidiaries	Unrestricted Non-Guarantor Subsidiaries	Consolidated Eliminations	Quicksilver Resources Inc. Consolidated
Revenue	$ 634,321	$ 4,395	$ 188,769	$ (2,014)	$ 825,471	$ 91,706	$ (84,442)	$ 832,735
Operating expense	1,202,124	9,413	273,969	(2,014)	1,483,492	47,610	(84,494)	1,446,608
Equity in net earnings of subsidiaries	(52,643)	27,161	-	52,643	27,161	-	(27,161)	-
Operating income (loss)	(620,446)	22,143	(85,200)	52,643	(630,860)	44,096	(27,109)	(613,873)
Income from earnings of BBEP	75,444	-	-	-	75,444	-	-	75,444
Impairment of investment in BBEP	(102,084)	-	-	-	(102,084)	-	-	(102,084)
Interest expense and other	(180,980)	3,725	(8,526)	-	(185,781)	(8,518)	(2,044)	(196,343)
Income tax (expense) benefit	270,593	(9,054)	24,269	-	285,808	5,809	-	291,617
Discontinued operations	-	-	-	-	-	(1,992)	1,992	-
Net income (loss)	$ (557,473)	$ 16,814	$ (69,457)	$ 52,643	$ (557,473)	$ 39,395	$ (27,161)	$ (545,239)
Net income attributable to noncontrolling interests	-	-	-	-	-	(12,234)	-	(12,234)
Net income (loss) attributable to Quicksilver	$ (557,473)	$ 16,814	$ (69,457)	$ 52,643	$ (557,473)	$ 27,161	$ (27,161)	$ (557,473)

For The Year Ended December 31, 2008

(In thousands)

	Quicksilver Resources Inc.	Restricted Guarantor Subsidiaries	Restricted Non-Guarantor Subsidiaries	Restricted Subsidiary Eliminations	Quicksilver and Restricted Subsidiaries	Unrestricted Non-Guarantor Subsidiaries	Eliminations	Quicksilver Resources Inc. Consolidated
Revenue	$ 600,906	$ 514	$ 187,126	$ (426)	$ 788,120	$ 76,084	$ (63,563)	$ 800,641
Operating expense	976,984	11,157	86,937	(426)	1,074,652	38,659	(62,973)	1,050,338
Equity in net earnings of subsidiaries	74,331	21,762	-	(74,331)	21,762	-	(21,762)	-
Operating income (loss)	(301,747)	11,119	100,189	(74,331)	(264,770)	37,425	(22,352)	(249,697)
Income from earnings of BBEP	93,298	-	-	-	93,298	-	-	93,298
Impairment of investment in BBEP	(320,387)	-	-	-	(320,387)	-	-	(320,387)
Interest expense and other	(89,657)	6,023	(14,491)	-	(98,125)	(8,426)	(1,740)	(108,291)
Income tax (expense) benefit	240,217	(6,000)	(22,509)	-	211,708	(253)	-	211,455
Discontinued operations	-	-	-	-	-	(2,330)	2,330	-
Net income (loss)	$ (378,276)	$ 11,142	$ 63,189	$ (74,331)	$ (378,276)	$ 26,416	$ (21,762)	$ (373,622)
Net income attributable to noncontrolling interests	-	-	-	-	-	(4,654)	-	(4,654)
Net income (loss) attributable to Quicksilver	$ (378,276)	$ 11,142	$ 63,189	$ (74,331)	$ (378,276)	$ 21,762	$ (21,762)	$ (378,276)

For The Year Ended December 31, 2007

(In thousands)

	Quicksilver Resources Inc.	Guarantor Subsidiaries	Restricted Non-Guarantor Subsidiaries	Restricted Subsidiary Eliminations	Quicksilver and Restricted Subsidiaries	Unrestricted Non-Guarantor Subsidiaries	Eliminations	Quicksilver Resources Inc. Consolidated
Revenue	$ 367,894	$ -	$ 187,154	$ (160)	$ 554,888	$ 35,695	$ (29,325)	$ 561,258
Operating expense	241,174	601	88,517	(160)	330,132	22,513	(29,123)	323,522
Income from equity affiliates	14	-	647	-	661	-	-	661
Gain on sale of properties	628,709	-	-	-	628,709	-	-	628,709
Loss on natural gas supply contracts	(63,525)	-	-	-	(63,525)	-	-	(63,525)
Equity in net earnings of subsidiaries	73,468	7,407	-	(73,468)	7,407	-	(7,407)	-
Operating income (loss)	765,386	6,806	99,284	(73,468)	798,008	13,182	(7,609)	803,581
Interest expense and other	(56,212)	2,609	(14,776)	-	(68,379)	(4,021)	(375)	(72,775)
Income tax (expense) benefit	(233,784)	(3,228)	(17,036)	-	(254,048)	(313)	-	(254,361)
Discontinued operations	-	-	-	-	-	(592)	592	-
Net income (loss)	$ 475,390	$ 6,187	$ 67,472	$ (73,468)	$ 475,581	$ 8,256	$ (7,392)	$ 476,445
Net income attributable to noncontrolling interests	-	(191)	-	-	(191)	(864)	-	(1,055)
Net income (loss) attributable to Quicksilver	$ 475,390	$ 5,996	$ 67,472	$ (73,468)	$ 475,390	$ 7,392	$ (7,392)	$ 475,390

Condensed Consolidating Statements of Cash Flows

	For The Year Ended December 31, 2009							
	Quicksilver Resources Inc.	Restricted Guarantor Subsidiaries	Restricted Non-Guarantor Subsidiaries	Restricted Subsidiary Eliminations	Quicksilver and Restricted Subsidiaries	Unrestricted Non-Guarantor Subsidiaries	Eliminations	Quicksilver Resources Inc. Consolidated
				(In thousands)				
Net cash flow provided by operating activities	$ 358,342	$ 73,202	$ 148,280	$ -	$ 579,824	$ 68,133	$ (35,717)	$ 612,240
Purchases of property, plant and equipment	(474,659)	(73,202)	(94,209)	-	(642,070)	(54,818)	3,050	(693,838)
Proceeds from sales of property, plant and equipment	220,206	-	768	-	220,974	-	-	220,974
Net cash flow used for investing activities	(254,453)	(73,202)	(93,441)	-	(421,096)	(54,818)	3,050	(472,864)
Issuance of debt	1,305,137	-	59,590	-	1,364,727	56,000	-	1,420,727
Repayments of debt	(1,428,105)	-	(116,025)	-	(1,544,130)	(105,500)	-	(1,649,630)
Debt issuance costs	(29,901)	-	(1,125)	-	(31,026)	(1,446)	-	(32,472)
Repayments to parent	-	-	-	-	-	(5,645)	5,645	-
Gas Purchase Commitment — net	44,119	-	-	-	44,119	-	-	44,119
Issuance of KGS common units		-	-	-	-	80,729	-	80,729
Distributions to parent		-	-	-	-	(27,022)	27,022	-
Distributions to noncontrolling interests	-	-	-	-	-	(9,925)	-	(9,925)
Proceeds from exercise of stock options	4,046	-	-	-	4,046	-	-	4,046
Purchase of treasury stock	(922)	-	-	-	(922)	-	-	(922)
Other	63	-	-	-	63	(63)	-	-
Net cash flow provided by (used for) financing activities	(105,563)	-	(57,560)	-	(163,123)	(12,872)	32,667	(143,328)
Effect of exchange rates on cash	-	-	2,889	-	2,889	-	-	2,889
Net decrease in cash and equivalents	(1,674)	-	168	-	(1,506)	443	-	(1,063)
Cash and equivalents at beginning of period	1,679	-	866	-	2,545	303	-	2,848
Cash and equivalents at end of period	$ 5	$ -	$ 1,034	$ -	$ 1,039	$ 746	$ -	$ 1,785

	For The Year Ended December 31, 2008							
	Quicksilver Resources Inc.	Restricted Guarantor Subsidiaries	Restricted Non-Guarantor Subsidiaries	Restricted Subsidiary Eliminations	Quicksilver and Restricted Subsidiaries	Unrestricted Non-Guarantor Subsidiaries	Eliminations	Quicksilver Resources Inc. Consolidated
				(In thousands)				
Net cash flow provided by operations	$ 290,160	$ -	$ 137,005	$ -	$ 427,165	$ 52,683	$ (23,282)	$ 456,566
Purchases of property, plant and equipment	(1,995,791)	-	(136,057)	-	(2,131,848)	(148,079)	-	(2,279,927)
Proceeds from sale of equipment to subsidiaries	42,914	-	-	-	42,914	-	(42,914)	-
Proceeds from sales of property, plant and equipment	721	-	618	-	1,339	-	-	1,339
Net cash flow used for investing activities	(1,952,156)	-	(135,439)	-	(2,087,595)	(148,079)	(42,914)	(2,278,588)
Issuance of debt	2,570,611	-	208,161	-	2,778,772	169,900	-	2,948,672
Repayments of debt	(886,429)	-	(209,734)	-	(1,096,163)	-	-	(1,096,163)
Debt issuance costs	(24,733)	-	-	-	(24,733)	(486)	-	(25,219)
Payments to parent	-	-	-	-	-	(42,914)	42,914	-
Distributions to parent	-	-	-	-	-	(23,282)	23,282	-
Distributions to noncontrolling interests	-	-	-	-	-	(8,644)	-	(8,644)
Proceeds from exercise of stock options	1,244	-	-	-	1,244	-	-	1,244
Purchase of treasury stock	(23,137)	-	-	-	(23,137)	-	-	(23,137)
Net cash flow provided by (used for) financing activities	1,637,556	-	(1,573)	-	1,635,983	94,574	66,196	1,796,753
Effect of exchange rates on cash	(893)	-	784	-	(109)	-	-	(109)
Net decrease in cash and equivalents	(25,333)	-	777	-	(24,556)	(822)	-	(25,378)
Cash and equivalents at beginning of period	27,012	-	89	-	27,101	1,125	-	28,226
Cash and equivalents at end of period	$ 1,679	$ -	$ 866	$ -	$ 2,545	$ 303	$ -	$ 2,848

	For The Year Ended December 31, 2007							
	Quicksilver Resources Inc.	Restricted Guarantor Subsidiaries	Restricted Non-Guarantor Subsidiaries	Restricted Subsidiary Eliminations	Quicksilver and Restricted Subsidiaries	Unrestricted Non-Guarantor Subsidiaries	Eliminations	Quicksilver Resources Inc. Consolidated
	(In thousands)							
Net cash flow provided by operations	$ 190,777	$ (596)	$ 116,935	$ -	$ 307,116	$ 14,949	$ (2,961)	$ 319,104
Purchases of property, plant and equipment	(824,321)	(267)	(151,807)	-	(976,395)	(73,797)	29,508	(1,020,684)
Investment in subsidiaries and affiliates	(38,908)	-	-	-	(38,908)	-	38,908	-
Return on investment in subsidiaries and affiliates	121,577	-	171	-	121,748	-	(112,113)	9,635
Proceeds from sales of property, plant and equipment	741,297	-	-	-	741,297	-	-	741,297
Net cash flow used for investing activities	(355)	(267)	(151,636)	-	(152,258)	(73,797)	(43,697)	(269,752)
Issuance of debt	594,500	-	218,321	-	812,821	5,000	-	817,821
Repayments of debt	(777,866)	-	(190,691)	-	(968,557)	-	-	(968,557)
Debt issuance costs	(3,148)	-	(664)	-	(3,812)	(1,318)	-	(5,130)
Proceeds from sale of KGS units, net	-	-	-	-	-	109,642	-	109,642
Contributions from noncontrolling interests	-	-	-	-	-	167	-	167
Contributions from parent	-	863	-	-	863	67,553	(68,416)	-
Distributions to parent	-	-	-	-	-	(115,074)	115,074	-
Distributions to noncontrolling interests	-	-	-	-	-	(8,794)	-	(8,794)
Proceeds from exercise of stock options	21,387	-	-	-	21,387	-	-	21,387
Excess tax benefits on exercise of stock options	2,755	-	-	-	2,755	-	-	2,755
Purchase of treasury stock	(1,567)	-	-	-	(1,567)	-	-	(1,567)
Net cash flow provided by (used for) financing activities	(163,939)	863	26,966	-	(136,110)	57,176	46,658	(32,276)
Effect of exchange rates on cash	446	-	5,423	-	5,869	-	-	5,869
Net decrease in cash and equivalents	26,929	-	(2,312)	-	24,617	(1,672)	-	22,945
Cash and equivalents at beginning of period	83	-	2,401	-	2,484	2,797	-	5,281
Cash and equivalents at end of period	$ 27,012	$ -	$ 89	$ -	$ 27,101	$ 1,125	$ -	$ 28,226

21. 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 in the U.S., where we provide natural gas gathering and processing services predominantly through KGS. Revenue earned by KGS for the gathering and processing 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.

	Exploration & Production		Processing &			Quicksilver
	United States	Canada	Gathering	Corporate	Elimination	Consolidated
			(In thousands)			
2009						
Revenue	$ 634,321	$ 188,770	$ 99,817	$ -	$ (90,173)	$ 832,735
DD&A	134,066	38,965	26,682	1,674	-	201,387
Impairment related to oil and gas properties	786,867	192,673	-	-	-	979,540
Operating income (loss)	(500,164)	(81,529)	46,737	(78,917)	-	(613,873)
Investment in equity affiliates	112,763	-	-	-	-	112,763
Property, plant and equipment – net	1,968,430	491,528	614,359	11,623	-	3,085,940
Property and equipment costs incurred	391,916	91,949	115,655	2,161	-	601,681
2008						
Revenue	$ 600,292	$ 187,740	$ 78,572	$ -	$ (65,963)	$ 800,641
DD&A	127,010	44,948	15,134	1,104	-	188,196
Impairment related to oil and gas properties	624,315	-	9,200	-	-	633,515
Operating income	(321,756)	104,131	34,879	(66,951)	-	(249,697)
Investment in equity affiliates	150,503	-	-	-	-	150,503
Property, plant and equipment – net	2,716,754	550,413	519,447	11,101	-	3,797,715
Property and equipment costs incurred	2,173,469	138,360	265,222	7,984	-	2,585,035
2007						
Revenue	$ 396,768	$ 158,121	$ 35,941	$ -	$ (29,572)	$ 561,258
DD&A	72,132	39,445	8,146	974	-	120,697
Operating income	750,703	85,155	12,380	(44,657)	-	803,581
Investment in equity affiliates	420,171	-	-	-	-	420,171
Property, plant and equipment – net	1,290,728	571,496	275,807	4,315	-	2,142,346
Property and equipment costs incurred	758,601	115,073	168,523	2,017	-	1,044,214

22. SUPPLEMENTAL CASH FLOW INFORMATION

Cash paid for interest and income taxes is as follows:

	Years Ended December 31,		
	2009	2008	2007
		(In thousands)	
Interest	$ 128,217	$ 83,400	$ 69,038
Income taxes	(41,267)	49,433	-

Other significant non-cash transactions are as follows:

	Years Ended December 31,		
	2009	2008	2007
		(In thousands)	
Working capital related to capital expenditures	$ 118,294	$ 230,624	$ 159,819
Issuance of common stock as consideration for the Alliance Acquisition	-	262,092	-
Noncash acquisition of interest in BBEP earnings	-	-	429,618
Tax benefit recognized on employee stock option exercises	-	-	2,755

23. EMPLOYEE BENEFITS

Quicksilver has a 401(k) retirement plan available to all U.S. full time employees who are at least 21 years of age. We make matching contributions and a fixed annual contribution and have the ability to make discretionary contributions to the plan. Expenses associated with company contributions were $2.3 million, $2.4 million and $1.6 million for 2009, 2008 and 2007, respectively.

We have a retirement plan available to all Canadian employees. The plan provides for a match of employees' contributions by us and a fixed annual contribution. Expenses associated with company contributions were $0.8 million, $0.8 million and $0.7 million for the 2009, 2008 and 2007, respectively.

We maintain a self-funded health benefit plan that covers all eligible U.S. employees. The plan has been reinsured on an individual claim and total group claim basis. Quicksilver is responsible for payment of the first $75,000 for each individual claim and also purchased aggregate level reinsurance for payment of claims up to $1 million over the estimated maximum claim liability. For 2009, 2008 and 2007 we recognized expenses of $4.6 million, $4.4 million and $3.2 million, respectively, for this plan.

24. RELATED PARTY TRANSACTIONS

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

We paid $0.7 million, $1.9 million and $2.1 million in 2009, 2008 and 2007, respectively, for rent on buildings owned by entities controlled by members of the Darden family. Rental rates were determined based on comparable rates charged by third parties. In October 2008, we completed the purchase of our headquarters building in Fort Worth, Texas for $6.4 million, the estimated fair value of the building, from an entity controlled by members of the Darden family. Subsequently, we entered into a property management agreement with an affiliate of the seller to which we paid $14,000 during the remainder of 2008 and $0.1 million in 2009. Annual lease payments on the purchased building prior to its acquisition had been $1.1 million.

During 2009, 2008 and 2007, we paid $0.2 million, $0.9 million and $0.2 million for use of an airplane owned by an entity controlled by members of the Darden family. Usage rates were determined based upon comparable rates charged by third parties.

We paid $0.2 million in 2009 and 2007 primarily for delay rentals under leases for over 5,000 acres held by a related entity. The lease terms were determined based on comparable prices and terms granted to third parties with respect to similar leases in the area. No payments were made in 2008.

Payments received in 2009, 2008 and 2007 from Mercury for sublease rentals, employee insurance coverage and administrative services were $0.3 million, $0.3 million and $0.2 million, respectively.

In October 2008, we paid $19.9 million for the purchase of 1,885,600 shares of our common stock from an entity controlled by members of the Darden family.

In May 2008, we signed a settlement agreement with Mercury in which Mercury agreed to make a payment of approximately $0.4 million in connection with issues related to the ownership and operation of certain oil and gas properties acquired from Mercury in 2001, including audit claims received with respect to certain of the acquired properties and the administration of employee benefits.

SUPPLEMENTAL SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following table presents selected quarterly financial data derived from our consolidated financial statements. This summary should be read in conjunction with our consolidated financial statements and related notes also contained in this Item 8 to our Annual Report on Form 10-K.

	Quarter Ended			
	March 31	**June 30**	**September 30**	**December 31**
	(In thousands, except per share data)			
2009 (1)(2)(3)				
Operating revenues	$ 185,932	$ 206,041	$ 206,657	$ 234,105
Operating income (loss)	(825,692)	10,573	103,703	97,543
Net income (loss)	(567,309)	(20,450)	2,159	34,154
Net income (loss) attributable to Quicksilver	(568,979)	(21,762)	730	32,538
Basic net earnings (loss) per share	$ (3.37)	$ (0.13)	$ -	$ 0.19
Diluted net earnings (loss) per share	(3.37)	(0.13)	-	0.19
2008 (4)				
Operating revenues	$ 157,617	$ 197,901	$ 236,262	$ 208,861
Operating income (loss)	70,723	107,103	119,990	(547,513)
Net income (loss)	41,642	52,323	(2,630)	(464,957)
Net income (loss) attributable to Quicksilver	41,134	51,335	(3,755)	(466,990)
Basic net earnings (loss) per share	$ 0.26	$ 0.32	$ (0.02)	$ (2.79)
Diluted net earnings (loss) per share	0.25	0.31	(0.02)	(2.79)

(1) Operating loss for the first quarter of 2009 includes a charge of $896.5 million for the impairment of our U.S. and Canadian oil and gas properties. Net loss for the first quarter of 2009 also includes $102.1 million for pre-tax income attributable to our proportionate ownership of BBEP and a pre-tax charge of $102.1 million for impairment of the related investment, respectively.

(2) Operating income for the second quarter of 2009 includes a charge of $70.6 million for the impairment of our Canadian oil and gas properties. Net loss for the second quarter of 2009 also includes $19.0 million of pre-tax income attributable to our proportionate ownership of BBEP.

(3) Operating income for the fourth quarter of 2009 includes a charge of $12.4 million for the impairment of our Canadian oil and gas properties. Net income for the fourth quarter of 2009 also includes $1.9 million pre-tax loss attributable to our proportionate ownership of BBEP.

(4) Operating loss for the fourth quarter of 2008 includes a charge of $633.5 million for the impairment of our U.S. oil and gas properties. Net loss for the fourth quarter of 2008 also includes $93.3 million for pre-tax income attributable to our proportionate ownership of BBEP and a pre-tax charge of $320.4 million for impairment of the related investment, respectively.

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

Proved oil and gas reserves estimates for our properties in the United States and Canada were prepared by independent petroleum engineers from Schlumberger Data and Consulting Services and LaRoche Petroleum Consultants, Ltd., respectively. The reserve reports were prepared in accordance with guidelines established by the SEC. Natural gas, NGL and oil prices used in the 2009 reserve reports are the unweighted average of the preceding 12-month first-day-of-the-month prices as of the date of the reserve reports without any escalation except in those instances where the sale of production was covered by contract, in which case the applicable contract prices, including fixed and determinable escalations, were used for the duration of the contract, and thereafter the unweighted 12-month average price was used. The prices used in the 2008 and 2007 reserve reports used end-of-year prices adjusted for local differentials and applicable contract prices which conforms to the SEC requirements then in effect. For all years, operating costs, production and ad valorem taxes and future development costs were based on year-end costs with no escalation.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures. The following reserve data represents estimates only and should not be construed as being exact. Moreover, the present values should not be construed as the current market value of our natural gas and oil reserves or the costs that would be incurred to obtain equivalent reserves.

As required by GAAP, we have also included separate disclosure and presentation of our share of BBEP's proved reserve because we account for BBEP by the equity method.

Consolidated Quicksilver (Excluding BBEP Reserves)

The changes in our proved reserves for the three years ended December 31, 2009 were as follows:

	Natural Gas (MMcf)			NGL (MBbl)			Oil (MBbl)		
	United States	Canada	Total	United States	Canada	Total	United States	Canada	Total
December 31, 2006	933,342	308,335	1,241,677	47,985	16	48,001	6,315	-	6,315
Revisions (5)	(30,494)	17,761	(12,733)	1,112	(1)	1,111	633	-	633
Extensions and discoveries (4)	302,098	24,463	326,561	46,571	-	46,571	658	-	658
Sales in place (1)	(503,651)	(1,446)	(505,097)	(3,147)	-	(3,147)	(3,947)	-	(3,947)
Production	(38,887)	(20,732)	(59,619)	(2,466)	(5)	(2,471)	(584)	-	(584)
December 31, 2007	662,408	328,381	990,789	90,055	10	90,065	3,075	-	3,075
Revisions (5)	(171,009)	4,923	(166,086)	(25,596)	-	(25,596)	(106)	-	(106)
Extensions and discoveries (4)	560,205	22,363	582,568	31,662	-	31,662	428	-	428
Purchases in place (2)	299,952	-	299,952	-	-	-	-	-	-
Sales in place	-	(27)	(27)	-	-	-	-	-	-
Production	(45,059)	(23,069)	(68,128)	(4,194)	(2)	(4,196)	(483)	-	(483)
December 31, 2008	1,306,497	332,571	1,639,068	91,927	8	91,935	2,914	-	2,914
Revisions (5)	(28,833)	(67,207)	(96,040)	(4,178)	7	(4,171)	205	1	206
Extensions and discoveries (4)	460,214	12,153	472,367	15,487	-	15,487	165	-	165
Purchases in place	314	-	314	-	-	-	-	-	-
Sales in place (3)	(120,539)	(44)	(120,583)	-	-	-	-	-	-
Production	(61,619)	(24,420)	(86,039)	(4,975)	(2)	(4,977)	(425)	(1)	(426)
December 31, 2009	1,556,034	253,053	1,809,087	98,261	13	98,274	2,859	-	2,859
Proved developed reserves									
December 31, 2007	379,917	260,029	639,946	50,738	10	50,748	2,763	-	2,763
December 31, 2008	756,191	278,668	1,034,859	56,181	8	56,189	2,509	-	2,509
December 31, 2009	1,044,140	223,300	1,267,440	60,997	13	61,010	2,467	-	2,467
Proved undeveloped reserves									
December 31, 2007	282,491	68,352	350,843	39,317	-	39,317	312	-	312
December 31, 2008	550,306	53,903	604,209	35,746	-	35,746	405	-	405
December 31, 2009	511,894	29,753	541,647	37,264	-	37,264	392	-	392

(1) Sales of reserves in place during 2007 relate principally to the BreitBurn Transaction, which is more fully described in Note 5 to our consolidated financial statements.

(2) Purchases of reserves in place during 2008 relate principally to the Alliance Transaction, which is more fully described in Note 4 to our consolidated financial statements.

(3) Sales of reserves in place during 2009 relate principally to the Eni Transaction, which is more fully described in Note 3 to our consolidated financial statements.

(4) Extensions and discoveries for each period presented represent extensions to reserves attributable to additional drilling activity subsequent to discovery. U.S. extensions and discoveries for:

- 2009 are 99% attributable to the Barnett Shale (of which 42% were proved developed);
- 2008 are 100% attributable to the Barnett Shale (of which 49% were proved developed); and
- 2007 are 96% attributable to the Barnett Shale (of which 49% were proved developed) and 4% were attributable to the Northeast Operations (which were all derecognized pursuant to the BreitBurn Transaction).

Canadian extensions and discoveries for 2009 are 47% attributable to the properties in Alberta and 53% are attributable the Horn River Basin properties in British Columbia. All Canadian extensions and discoveries for 2008 and 2007 are attributable to the gas projects in Alberta.

(5) Revisions for each period presented reflect upward (downward) changes in previous estimates attributable to new information gained primarily from development drilling activity and production history. Revisions include 132,846 MMcfe, (166,198) MMcfe and (55,584) MMcfd for such matters in 2009, 2008 and 2007, respectively. Revisions also include changes in previous estimates due to changes in sales price. Revisions include (251,676) MMcfe, (154,100) MMcfe, and 53,315 MMcfe for such sales price changes in 2009, 2008 and 2007.

The carrying value of our consolidated oil and gas assets as of December 31, 2009, 2008 and 2007 were as follows:

	United States	Canada	Consolidated
		(In thousands)	
2009			
Proved properties	$ 3,218,796	$ 728,880	$ 3,947,676
Unevaluated properties	340,707	117,330	458,037
Accumulated DD&A	(1,670,923)	(396,546)	(2,067,469)
Net capitalized costs	$ 1,888,580	$ 449,664	$ 2,338,244
2008			
Proved properties	$ 3,068,326	$ 553,505	$ 3,621,831
Unevaluated properties	462,943	80,590	543,533
Accumulated DD&A	(902,281)	(120,475)	(1,022,756)
Net capitalized costs	$ 2,628,988	$ 513,620	$ 3,142,608
2007			
Proved properties	$ 1,231,109	$ 580,186	$ 1,811,295
Unevaluated properties	163,274	51,954	215,228
Accumulated DD&A	(157,122)	(105,001)	(262,123)
Net capitalized costs	$ 1,237,261	$ 527,139	$ 1,764,400

Our consolidated capital costs incurred for acquisition, exploration and development activities during each of the three years ended December 31, 2009, were as follows:

	United States	Canada	Consolidated
		(In thousands)	
2009			
Proved acreage	$ 118	$ -	$ 118
Unproved acreage	11,300	2,658	13,958
Development costs	341,658	24,179	365,837
Exploration costs	32,798	59,402	92,200
Total	$ 385,874	$ 86,239	$ 472,113
2008			
Proved acreage	$ 787,172	$ -	$ 787,172
Unproved acreage	484,770	54,048	538,818
Development costs	836,032	68,629	904,661
Exploration costs	30,161	10,280	40,441
Total	$2,138,135	$ 132,957	$2,271,092
2007			
Proved acreage	$ -	$ -	$ -
Unproved acreage	17,031	31,448	48,479
Development costs	648,632	67,608	716,240
Exploration costs	75,862	11,953	87,815
Total	$ 741,525	$ 111,009	$ 852,534

Consolidated results of operations from our producing activities for the three years ended December 31, 2009, are set forth below:

	United States	Canada	Consolidated
		(In thousands)	
2009			
Natural gas, NGL and oil revenue	$ 608,013	$ 188,685	$ 796,698
Oil & gas production expense	112,935	38,661	151,596
Depletion & amortization expense	127,888	33,783	161,671
Impairment related to oil and gas properties	786,867	192,673	979,540
	(419,677)	(76,432)	(496,109)
Income tax expense (benefit)	(146,887)	(22,165)	(169,052)
Results from producing activities	$ (272,790)	$ (54,267)	$ (327,057)
2008			
Natural gas, NGL and oil revenue	$ 597,889	$ 182,899	$ 780,788
Oil & gas production expense	114,374	38,662	153,036
Depletion & amortization expense	120,845	40,337	161,182
Impairment related to oil and gas properties	624,315	–	624,315
	(261,645)	103,900	3,437
Income tax expense (benefit)	(91,576)	30,131	(61,445)
Results from producing activities	$ (170,069)	$ 73,769	$ 64,882
2007			
Natural gas, NGL and oil revenue	$ 392,841	$ 152,248	$ 545,089
Oil & gas production expense	119,630	33,521	153,151
Depletion & amortization expense	65,701	35,330	101,031
	207,510	83,397	290,907
Income tax expense	72,629	24,185	96,814
Results from producing activities	$ 134,881	$ 59,212	$ 194,093

The Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves ("Standardized Measure") do not purport to present the fair market value of the our natural gas and oil properties. An estimate of such value should consider, among other factors, anticipated future prices of natural gas and oil, the probability of recoveries in excess of existing proved reserves, the value of probable reserves and acreage prospects, estimated future capital and operating costs and perhaps different discount rates. It should be noted that estimates of reserve quantities, especially from new discoveries, are inherently imprecise and subject to substantial revision.

Under the Standardized Measure, future cash inflows for 2009 were estimated by applying the unweighted average of the preceding 12-month first-day-of-the-month prices, adjusted for contracts with price floors but excluding hedges, and unescalated year-end costs to the estimated future production of the year-end reserves. These prices have varied widely and have a significant impact on both the quantities and value of the proved reserves as reduced prices cause wells to reach the end of their economic life much sooner and also make certain proved undeveloped locations uneconomical, both of which reduce reserves. The following representative prices were used in the Standardized Measure and were adjusted by field for appropriate regional differentials:

	At December 31,		
	2009	2008 [1]	2007 [1]
Natural gas – Henry Hub	$ 3.87	$ 5.71	$ 6.80
Natural gas – AECO	3.76	5.44	6.35
NGL – Mont Belvieu, Texas	24.94	21.65	57.35
Oil – WTI Cushing	61.18	44.60	95.98

(1) The prices used for all 2008 and 2007 proved reserve estimates were year-end spot prices, which were previously required by guidance from the SEC and FASB then in effect. Additional information regarding the change during 2009 for reserve recognition guidance is included in Note 2 to our consolidated financial statements.

Future cash inflows were reduced by estimated future production and development costs based on year-end costs to determine pre-tax cash inflows. Future income taxes were computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the associated proved natural gas and oil properties. Tax credits and net operating loss carry forwards were also considered in the future income tax calculation. Future net cash inflows after income taxes were discounted using a 10% annual discount rate to arrive at the Standardized Measure.

The standardized measure of discounted cash flows related to proved oil and gas reserves at December 31, 2009, 2008 and 2007 were as follows:

	United States	Canada	Total
		(In thousands)	
December 31, 2009			
Future revenues	$ 7,787,422	$ 916,765	$ 8,704,187
Future production costs	(4,169,783)	(403,874)	(4,573,657)
Future development costs	(938,675)	(93,588)	(1,032,263)
Future income taxes	(222,576)	(47,125)	(269,701)
Future net cash flows	2,456,388	372,178	2,828,566
10% discount	(1,492,469)	(153,418)	(1,645,887)
Standardized measure of discounted future cash flows relating to proved reserves	$ 963,919	$ 218,760	$ 1,182,679
December 31, 2008			
Future revenues	$ 8,783,936	$ 1,764,268	$ 10,548,204
Future production costs	(4,162,737)	(551,395)	(4,714,132)
Future development costs	(1,140,466)	(113,800)	(1,254,266)
Future income taxes	(504,753)	(215,212)	(719,965)
Future net cash flows	2,975,980	883,861	3,859,841
10% discount	(1,623,862)	(441,717)	(2,065,579)
Standardized measure of discounted future cash flows relating to proved reserves	$ 1,352,118	$ 442,144	$ 1,794,262

	United States	Canada	Total
		(In thousands)	
December 31, 2007			
Future revenues	$ 9,566,791	$ 2,037,478	$ 11,604,269
Future production costs	(3,286,618)	(675,890)	(3,962,508)
Future development costs	(651,802)	(156,289)	(808,091)
Future income taxes	(1,772,021)	(228,883)	(2,000,904)
Future net cash flows	3,856,350	976,416	4,832,765
10% discount	(2,168,150)	(495,413)	(2,663,562)
Standardized measure of discounted future cash flows relating to proved reserves	$ 1,688,200	$ 481,003	$ 2,169,203

The primary changes in the standardized measure of discounted future net cash flows for the three years ended December 31, 2009, were as follows:

	Years Ended December 31,		
	2009	2008	2007
		(In thousands)	
Sales of oil and gas net of production costs	$ (645,102)	$ (628,333)	$ (392,116)
Net changes in price and production cost	(715,484)	(2,368,940)	1,048,432
Extensions and discoveries	561,544	1,630,418	1,045,296
Development costs incurred	205,781	373,124	170,686
Changes in estimated future development costs	81,754	(413,097)	(234,649)
Purchase and sale of reserves, net	(144,279)	722,662	(1,010,263)
Revision of estimates	(248,681)	(618,527)	(8,090)
Accretion of discount	192,325	324,064	196,275
Net change in income taxes	196,691	509,854	(293,374)
Timing and other differences	(96,132)	93,834	161,181
Net increase (decrease)	$ (611,583)	$ (374,941)	$ 683,378

Quicksilver Share of BBEP Reserves

The following disclosures required under GAAP represent Quicksilver's share of BBEP's reserves and BBEP's oil and gas operations, which are all located in the U.S. Notes 5 and 9 in our consolidated financial statements contain additional information regarding our relationship with BBEP. In addition, this Annual Report contains BBEP's financial statements, which are in Item 15 and have been included pursuant to SEC Rule 3-09.

The changes in our share of BBEP's oil and gas reserves were as follows:

	For The Years Ended December 31,								
	2009			2008			2007		
	Total (Mboe)	Gas (MMcf)	Oil (MBbl)	Total (Mboe)	Gas (MMcf)	Oil (MBbl)	Total (Mboe)	Gas (MMcf)	Oil (MBbl)
Beginning balance	42,038	189,176	9,471	45,314	160,864	17,465	—	—	—
Revision of previous estimates	6,191	(4,203)	6,891	(12,903)	(6,591)	(11,805)	—	—	—
Extensions, discoveries and other additions	—	—	—	—	—	—	38	—	38
Purchase of reserves in place [1]	—	—	—	12,389	43,982	5,060	46,238	162,181	18,169
Sale of reserves in place [1]	(566)	(543)	(476)	—	—	—	—	—	—
Production	(2,636)	(8,561)	(1,209)	(2,762)	(9,079)	(1,249)	(962)	(1,317)	(742)
Ending balance	45,027	175,869	14,677	42,038	189,176	9,471	45,314	160,864	17,465
Proved developed reserves									
Beginning balance	38,791	175,933	9,469	40,877	145,696	16,595	—	—	—
Ending balance	40,846	161,491	13,931	38,791	175,933	9,469	40,877	145,696	16,595
Proved undeveloped reserves									
Beginning balance	3,247	13,244	1,040	4,437	15,169	1,908	—	—	—
Ending balance	4,180	14,378	1,784	3,247	13,244	1,040	4,437	15,169	1,908

The following representative prices were used in BBEP's Standardized Measure:

	Years Ended December 31,		
	2009 [2]	2008 [3]	2007 [3]
Representative prices:			
Natural gas – Henry Hub	$ 3.87	$ 5.71	$ 6.80
Oil – WTI Cushing	61.18	44.60	95.95

(1) Amounts are included as needed to reconcile Quicksilver's portion of beginning reserves to ending reserves that result from changes in Quicksilver's proportionate ownership of BBEP.

(2) Prices used for 2009 proved reserve estimates were the unweighted average of the preceding 12-month first-day-of-the-month prices.

(3) The prices used for all 2008 and 2007 proved reserve estimates were year-end spot prices, which were previously required by guidance from the SEC and FASB then in effect.

The following table summarizes the carrying value of our portion of BBEP's consolidated oil and gas assets as of December 31, 2009 and 2008.

	At December 31,	
	2009	2008
	(In thousands)	
Proved properties and related producing assets	$ 698,541	$ 703,654
Pipeline and processing facilities	55,243	45,719
Unproved properties	79,166	85,120
Accumulated depreciation, depletion and amortization	(130,204)	(90,678)
Net capitalized costs	$ 702,747	$ 743,815

The following table summarizes our share of the capital costs incurred by BBEP during the three years ended December 31, 2009:

	2009	2008	2007
		(In thousands)	
Proved properties	$ -	$ -	$ 457,726
Unproved properties	-	-	67,950
Development costs	11,598	52,524	8,586
Asset retirement costs	1,975	553	1,141
Pipelines and processing facilities	-	-	15,546
Total	$ 13,573	$ 53,077	$ 550,949

The following table summarizes our share of BBEP's results of operations from its producing activities for the three years ended December 31, 2009:

	2009	2008	2007
		(In thousands)	
Oil, natural gas and NGL sales	$ 103,126	$ 189,560	$ 58,722
Realized gain (loss) on derivative instruments	67,836	(22,691)	(2,088)
Unrealized gain (loss) on derivative instruments	(88,644)	157,385	(33,080)
Operating costs	(56,029)	(65,706)	(23,565)
Depreciation, depletion & amortization	(42,194)	(72,460)	(9,325)
Income tax (expense) benefit	618	(786)	391
Results from producing activities	$ (15,287)	$ 185,302	$ (8,945)

The following table summarizes our share of BBEP's standardized measure of discounted cash flows related to its proved oil and gas reserves at December 31, 2009, 2008 and 2007:

	At December 31,		
	2009	2008	2007
		(In thousands)	
Future revenues	$1,552,493	$1,429,072	$ 2,597,342
Future development costs	(79,983)	(86,369)	(118,034)
Future production costs	(850,917)	(747,884)	(1,070,304)
Future net cash flows	621,593	594,819	1,409,004
10% discount	(314,290)	(354,610)	(799,884)
Standardized measure of discounted future cash flows relating to proved reserves	$ 307,303	$ 240,209	$ 609,120

The following table summarizes our share of the primary changes in BBEP's standardized measure of discounted future net cash flows for the three years ended December 31, 2009:

	At December 31,		
	2009	2008	2007
		(In thousands)	
Beginning balance	$240,209	$ 609,120	$ -
Sales, net of production costs	(47,097)	(128,854)	(35,157)
Net changes in sales and transfer prices, net of production expense	88,093	(529,993)	77,515
Previously estimated development costs incurred	11,748	23,400	4,921
Changes in estimated future development costs	(14,969)	(39,773)	(7,225)
Extensions, discoveries and improved recovery, net of costs	-	-	829
Purchase of reserves in place[(1)]	-	166,538	541,014
Sale of reserves in place[(1)]	(2,231)	-	-
Revision of quantity estimates and timing of production	7,590	57,205	17,270
Accretion of discount	23,960	77,566	9,953
Ending balance	$307,303	$ 240,209	$609,120

(1) Amounts are included as needed to reconcile Quicksilver's portion of beginning value to ending value that result from changes in Quicksilver's proportionate ownership of BBEP.

ITEM 9. Changes in and Disagreements with Accountants or Accounting and Financial Disclosure

None.

ITEM 9A. Controls and Procedures

Disclosure Controls and Procedures

Disclosure controls and procedures, as defined in SEC literature, are controls and other procedures that are designed to ensure that the information that we are required to disclose in the reports that we file or submit to the SEC is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure.

In connection with the preparation of this Annual Report on Form 10-K, our management, under the supervision and with the participation of our Chief Executive Officer and our Chief Financial Officer, carried out an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures as of December 31, 2009.

Based on this evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective at the reasonable assurance level as of December 31, 2009.

Management's Report on Internal Control Over Financial Reporting

Our management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rules 13a-15(f) under the Exchange Act. Because of its inherent limitations, internal control over financial reporting may not prevent or detect all misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with existing policies or procedures may deteriorate.

Under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, our management conducted an assessment of our internal control over financial reporting as of December 31, 2009, based on the criteria established in *Internal Control — Integrated Framework*, issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on this assessment, our management has concluded that, as of December 31, 2009, our internal control over financial reporting was effective.

The effectiveness of our internal control over financial reporting as of December 31, 2009, has been audited by Deloitte & Touche LLP, our independent registered public accounting firm, and they have issued an attestation report expressing an unqualified opinion on the effectiveness of our internal control over financial reports, as stated in their report included herein.

Changes in Internal Control Over Financial Reporting

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Quicksilver Resources Inc.
Fort Worth, Texas

We have audited the internal control over financial reporting of Quicksilver Resources Inc. and subsidiaries (the "Company") as of December 31, 2009, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2009 of the Company and our report dated March 15, 2010 an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP

Fort Worth, Texas
March 15, 2010

ITEM 9B. Other Information

None.

PART III

ITEM 10. Directors, Executive Officers and Corporate Governance

The information concerning our directors set forth under "Corporate Governance Matters" in the proxy statement for our May 19, 2010 annual meeting of stockholders ("2010 Proxy Statement") is incorporated herein by reference. The information concerning any changes to the procedure by which a security holder may recommend nominees to the board of directors set forth under "Corporate Governance Matters - Committees of the Board" in the 2010 Proxy Statement is incorporated herein by reference. Certain information concerning our executive officers is set forth under the heading "Business - Executive Officers of the Registrant" in Item 1 of this Annual Report. The information concerning compliance with Section 16(a) of the Exchange Act set forth under "Section 16(a) Beneficial Ownership Reporting Compliance" in the 2010 Proxy Statement is incorporated herein by reference.

The information concerning our audit committee set forth under "Corporate Governance Matters - Committees of the Board" in the 2010 Proxy Statement is incorporated herein by reference.

The information regarding our Code of Ethics set forth under "Corporate Governance Matters - Corporate Governance Principles, Processes and Code of Business Conduct and Ethics" in the 2010 Proxy Statement is incorporated herein by reference.

ITEM 11. Executive Compensation

The information set forth under "Executive Compensation," "Corporate Governance Matters - Director Compensation for 2009" and "Certain Relationships and Related Transactions" in our 2010 Proxy Statement is incorporated herein by reference.

ITEM 12. Security Ownership of Management and Certain Beneficial Owners and Management and Related Stockholder Matters

The information set forth under "Security Ownership of Management and Certain Beneficial Holders" in the 2010 Proxy Statement for is incorporated herein by reference. The information regarding our equity plans under which shares of our common stock are authorized for issuance as set forth under "Equity Compensation Plan Information" in the 2010 Proxy Statement is incorporated herein by reference.

ITEM 13. Certain Relationships and Related Transactions, and Director Independence

The information set forth under "Certain Relationships and Related Transactions" in the 2010 Proxy Statement is incorporated herein by reference.

Information regarding our directors' independence set forth under "Corporate Governance Matters - Independent Directors" in the 2010 Proxy Statement is incorporated herein by reference.

ITEM 14. Principal Accountant Fees and Services

The information set forth under "Independent Registered Public Accountants" in the 2010 Proxy Statement is incorporated herein by reference.

PART IV

ITEM 15. Exhibits and Financial Statement Schedules

The following are filed as part of this Annual Report:

Financial Statements

See the index to the consolidated financial statements and related footnotes and other supplemental information included in Item 8 of this Annual Report, which identifies the financial statements filed herewith.

Financial Statement Schedules

The audited financial statements and related footnotes of BBEP, Quicksilver's equity method investment, included in our 2009 Form 10-K have been intentionally omitted from this Annual Report.

All other schedules are omitted from this item because the information is inapplicable or is presented in the consolidated financial statements and related notes in Item 8 of this Annual Report.

Exhibit No.	Sequential Description
**2.1	Contribution Agreement, dated September 11, 2007, between Quicksilver Resources Inc. and BreitBurn Operating L.P. (filed as Exhibit 10.2 to the Company's Form 8-K filed November 7, 2007 and included herein by reference.)
**2.2	Purchase and Sale Agreement, dated as of July 3, 2008, among Nortex Minerals, L.P., Petrus Investment, L.P., Petrus Development, L.P., and Perot Investment Partners, Ltd., as Sellers, and Quicksilver Resources Inc., as Purchaser (filed as Exhibit 10.1 to the Company's Form 8-K filed July 7, 2008 and included herein by reference).
**2.3	Purchase and Sale Agreement, dated as of July 3, 2008, among Hillwood Oil & Gas, L.P., Burtex Minerals, L.P., Chief Resources, LP, Hillwood Alliance Operating Company, L.P., Chief Resources Alliance Pipeline LLC, Chief Oil & Gas LLC, Berry Barnett, L.P., Collins and Young, L.L.C. and Mark Rollins, as Sellers, and Quicksilver Resources Inc., as Purchaser (filed as Exhibit 10.2 to the Company's Form 8-K filed July 7, 2008 and included herein by reference).
3.1	Amended and Restated Certificate of Incorporation of Quicksilver Resources Inc. filed with the Secretary of State of the State of Delaware on May 21, 2008 (filed as Exhibit 4.1 to the Company's Form S-3, File No. 333-151847, filed June 23, 2008 and included herein by reference).
3.2	Amended and Restated Certificate of Designation of Series A Junior Participating Preferred Stock of Quicksilver Resources Inc. (filed as Exhibit 3.3 to the Company's Form 10-Q filed May 6, 2006 and included herein by reference).
3.3	Amended and Restated Bylaws of Quicksilver Resources Inc. (filed as Exhibit 3.1 to the Company's Form 8-K filed November 16, 2007 and included herein by reference).
4.1	Indenture Agreement for 1.875% Convertible Subordinated Debentures Due 2024, dated as of November 1, 2004, between Quicksilver Resources Inc., as Issuer, and The Bank of New York, as Trustee (as successor in interest to JPMorgan Chase Bank, National Association) (filed as Exhibit 4.1 to the Company's Form 8-K filed November 1, 2004 and included herein by reference).
4.2	First Supplemental Indenture, dated July 31, 2009, between Quicksilver Resources Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (filed as Exhibit 4.2 to the Company's Form 10-Q filed August 10, 2009 and included herein by reference).
4.3	Indenture, dated as of December 22, 2005, between Quicksilver Resources Inc. and The Bank of New York, as Trustee (as successor in interest to JPMorgan Chase Bank, National Association) (filed as Exhibit 4.7 to the Company's Form S-3, File No. 333-130597, filed December 22, 2005 and included herein by reference).
4.4	First Supplemental Indenture, dated as of March 16, 2006, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York, as Trustee (as successor in interest to JPMorgan Chase Bank, National Association) (filed as Exhibit 4.1 to the Company's Form 8-K filed March 21, 2006 and included herein by reference).

Exhibit No.	Sequential Description
*4.5	Second Supplemental Indenture, dated as of July 31, 2006, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York, as Trustee (as successor in interest to JPMorgan Chase Bank, National Association).
4.6	Third Supplemental Indenture, dated as of September 26, 2006, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York, as Trustee (as successor in interest to JPMorgan Chase Bank, National Association) (filed as Exhibit 4.1 to the Company's Form 10-Q filed November 7, 2006 and included herein by reference).
*4.7	Fourth Supplemental Indenture, dated as of October 31, 2007, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York, as Trustee (as successor in interest to JPMorgan Chase Bank, National Association).
4.8	Fifth Supplemental Indenture, dated as of June 27, 2008, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York Trust Company, N.A., as trustee (filed as Exhibit 4.1 to the Company's Form 8-K filed June 30, 2008 and included herein by reference).
4.9	Sixth Supplemental Indenture, dated as of July 10, 2008, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee (filed as Exhibit 4.1 to the Company's Form 8-K filed July 10, 2008 and included herein by reference).
4.10	Seventh Supplemental Indenture, dated as of June 25, 2009, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee (filed as Exhibit 4.1 to the Company's Form 8-K filed June 26, 2009 and included herein by reference).
4.11	Eighth Supplemental Indenture, dated as of August 14, 2009, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee (filed as Exhibit 4.1 to the Company's Form 8-K filed August 17, 2009 and included herein by reference).
4.12	Amended and Restated Rights Agreement, dated as of December 20, 2005, between Quicksilver Resources Inc. and Mellon Investor Services LLC, as Rights Agent (filed as Exhibit 4.1 to the Company's Form 8-A/A (Amendment No. 1) filed December 21, 2005 and included herein by reference).
10.1	Wells Agreement dated as of December 15, 1970, between Union Oil Company of California and Montana Power Company (filed as Exhibit 10.5 to the Company's Predecessor, MSR Exploration Ltd.'s Form S-4/A, File No. 333-29769, filed August 21, 1997 and included herein by reference).
+ 10.2	Quicksilver Resources Inc. Amended and Restated 1999 Stock Option and Retention Stock Plan (filed as Exhibit 10.6 to the Company's Form 8-K filed November 24, 2008 and included herein by reference).
+ 10.3	Form of Incentive Stock Option Agreement pursuant to the Quicksilver Resources Inc. Amended and Restated 1999 Stock Option and Retention Stock Plan (filed as Exhibit 10.2 to the Company's Form 8-K filed January 28, 2005 and included herein by reference).
+ 10.4	Form of Non-Qualified Stock Option Agreement pursuant to the Quicksilver Resources Inc. Amended and Restated 1999 Stock Option and Retention Stock Plan (filed as Exhibit 10.3 to the Company's Form 8-K filed January 28, 2005 and included herein by reference).
+ 10.5	Form of Retention Share Agreement pursuant to the Quicksilver Resources Inc. Amended and Restated 1999 Stock Option and Retention Stock Plan (filed as Exhibit 10.3 to the Company's Form 8-K filed April 19, 2005 and included herein by reference).
+ 10.6	Form of Restricted Stock Unit Agreement pursuant to the Quicksilver Resources Inc. Amended and Restated 1999 Stock Option and Retention Stock Plan (filed as Exhibit 10.4 to the Company's Form 8-K filed April 19, 2005 and included herein by reference).
+ 10.7	Quicksilver Resources Inc. Amended and Restated 2004 Non-Employee Director Equity Plan (filed as Exhibit 10.4 to the Company's Form 8-K filed May 25, 2007 and included herein by reference).

Exhibit No.	Sequential Description
+ 10.8	Form of Non-Qualified Stock Option Agreement pursuant to the Quicksilver Resources Inc. Amended and Restated 2004 Non-Employee Director Equity Plan (filed as Exhibit 10.4 to the Company's Form 8-K filed January 28, 2005 and included herein by reference).
+ 10.9	Form of Restricted Share Agreement pursuant to the Quicksilver Resources Inc. Amended and Restated 2004 Non-Employee Director Equity Plan (filed as Exhibit 10.2 to the Company's Form 8-K filed May 18, 2005 and included herein by reference).
+ 10.10	Quicksilver Resources Inc. Third Amended and Restated 2006 Equity Plan (filed as Exhibit 10.1 to the Company's Form 8-K filed May 22, 2009 and included herein by reference).
+ 10.11	Form of Restricted Share Agreement pursuant to the Quicksilver Resources Inc. 2006 Equity Plan, as amended (filed as Exhibit 10.2 to the Company's Form 8-K filed May 25, 2006 and included herein by reference).
+ 10.12	Form of Restricted Stock Unit Agreement pursuant to the Quicksilver Resources Inc. 2006 Equity Plan, as amended (filed as Exhibit 10.2 to the Company's Form 8-K filed November 24, 2008 and included herein by reference).
+ 10.13	Form of Quicksilver Resources Canada Inc. Restricted Stock Unit Agreement (Cash Settlement) pursuant to the Quicksilver Resources Inc. 2006 Equity Plan, as amended (filed as Exhibit 10.3 to the Company's Form 8-K filed November 24, 2008 and included herein by reference).
+ 10.14	Form of Quicksilver Resources Canada Inc. Restricted Stock Unit Agreement (Stock Settlement) pursuant to the Quicksilver Resources Inc. 2006 Equity Plan, as amended (filed as Exhibit 10.4 to the Company's Form 8-K filed November 24, 2008 and included herein by reference).
+ 10.15	Form of Incentive Stock Option Agreement pursuant to the Quicksilver Resources Inc. 2006 Equity Plan, as amended (filed as Exhibit 10.5 to the Company's Form 8-K filed May 25, 2006 and included herein by reference).
+ 10.16	Form of Nonqualified Stock Option Agreement pursuant to the Quicksilver Resources Inc. 2006 Equity Plan, as amended (filed as Exhibit 10.6 to the Company's Form 8-K filed May 25, 2006 and included herein by reference).
+ 10.17	Form of Non-Employee Director Nonqualified Stock Option Agreement pursuant to the Quicksilver Resources Inc. 2006 Equity Plan, as amended (One-Year Vesting) (filed as Exhibit 10.8 to the Company's Form 8-K filed May 25, 2006 and included herein by reference).
+ 10.18	Form of Non-Employee Director Nonqualified Stock Option Agreement pursuant to the Quicksilver Resources Inc. 2006 Equity Plan, as amended (Three-Year Vesting) (filed as Exhibit 10.5 to the Company's Form 8-K filed November 24, 2008 and included herein by reference).
+ 10.19	Form of Non-Employee Director Restricted Share Agreement pursuant to the Quicksilver Resources Inc. 2006 Equity Plan, as amended (One-Year Vesting) (filed as Exhibit 10.7 to the Company's Form 8-K filed May 25, 2006 and included herein by reference).
+ 10.20	Form of Non-Employee Director Restricted Share Agreement pursuant to the Quicksilver Resources Inc. 2006 Equity Plan, as amended (Three-Year Vesting) (filed as Exhibit 10.2 to the Company's Form 8-K filed May 25, 2007 and included herein by reference).
+ 10.21	Quicksilver Resources Inc. 2008 Executive Bonus Plan (filed as Exhibit 10.1 to the Company's Form 8-K filed December 14, 2007 and included herein by reference).
*+ 10.22	Quicksilver Resources Inc. Amended and Restated 2009 Executive Bonus Plan.
+ 10.23	Quicksilver Resources Inc. 2010 Executive Bonus Plan (filed as Exhibit 10.1 to the Company's Form 8-K filed December 10, 2009 and included herein by reference).
+ 10.24	Quicksilver Resources Inc. Amended and Restated Change in Control Retention Incentive Plan (filed as Exhibit 10.9 to the Company's Form 8-K filed November 24, 2008 and included herein by reference).
+ 10.25	Quicksilver Resources Inc. Second Amended and Restated Key Employee Change in Control Retention Incentive Plan (filed as Exhibit 10.8 to the Company's Form 8-K filed November 24, 2008 and included herein by reference).

Exhibit No.	Sequential Description
+ 10.26	Quicksilver Resources Inc. Amended and Restated Executive Change in Control Retention Incentive Plan (filed as Exhibit 10.7 to the Company's Form 8-K filed November 24, 2008 and included herein by reference).
+ 10.27	Form of Director and Officer Indemnification Agreement (filed as Exhibit 10.1 to the Company's Form 8-K filed August 26, 2005 and included herein by reference).
10.28	Amended and Restated Credit Agreement, dated as of February 9, 2007, among Quicksilver Resources Inc. and the lenders identified therein (filed as Exhibit 10.1 to the Company's Form 8-K filed February 12, 2007 and included herein by reference).
10.29	Amended and Restated Credit Agreement, dated as of February 9, 2007, among Quicksilver Resources Canada Inc. and the lenders and/or agents identified therein (filed as Exhibit 10.2 to the Company's Form 8-K filed February 12, 2007 and included herein by reference).
* 10.30	First Amendment to Combined Credit Agreements, dated as of February 4, 2008, among Quicksilver Resources Inc., Quicksilver Resources Canada Inc. and the agents and combined lenders identified therein.
* 10.31	Second Amendment to Combined Credit Agreements, dated as of May 8, 2008, among Quicksilver Resources Inc., Quicksilver Resources Canada Inc. and the agents and combined lenders identified therein.
* 10.32	Third Amendment to Combined Credit Agreements, dated as of May 28, 2008, among Quicksilver Resources Inc., Quicksilver Resources Canada Inc. and the agents and combined lenders identified therein.
10.33	Fourth Amendment to Combined Credit Agreements, dated as of June 20, 2008, among Quicksilver Resources Inc., Quicksilver Resources Canada Inc. and the agents and combined lenders identified therein (filed as Exhibit 10.1 to the Company's Form 8-K filed June 25, 2008 and included herein by reference).
10.34	Fifth Amendment to Combined Credit Agreements, dated as of August 4, 2008, among Quicksilver Resources Inc., Quicksilver Resources Canada Inc. and the agents and combined lenders identified therein (filed as Exhibit 10.1 to the Company's Form 8-K filed August 5, 2008 and included herein by reference).
* 10.35	Sixth Amendment to Combined Credit Agreements, dated as of September 30, 2008, among Quicksilver Resources Inc., Quicksilver Resources Canada Inc. and the agents and combined lenders identified therein.
* 10.36	Seventh Amendment to Combined Credit Agreements, dated as of April 20, 2009, among Quicksilver Resources Inc., Quicksilver Resources Canada Inc. and the agents and combined lenders identified therein.
10.37	Eighth Amendment to Combined Credit Agreements, dated as of May 28, 2009, among Quicksilver Resources Inc., Quicksilver Resources Canada Inc. and the agents and combined lenders identified therein (filed as Exhibit 10.1 to the Company's Form 8-K filed June 17, 2009 and included herein by reference).
10.38	Credit Agreement, dated as of August 8, 2008, among Quicksilver Resources Inc., the lenders party thereto and Credit Suisse, Cayman Islands Branch, as administrative agent (filed as Exhibit 10.1 to the Company's Form 8-K filed August 8, 2008 and included herein by reference).
10.39	Amendment No. 1 to Credit Agreement, dated as of June 3, 2009, among Quicksilver Resources Inc., the lenders party thereto and Credit Suisse, Cayman Islands Branch, as administrative agent (filed as Exhibit 10.2 to the Company's Form 8-K filed June 17, 2009 and included herein by reference).
10.40	Registration Rights Agreement, dated as of November 1, 2007, between Quicksilver Resources Inc. and BreitBurn Energy L.P. (filed as Exhibit 10.1 to the Company's Form 8-K filed November 7, 2007 and included herein by reference).
+ 10.41	Quicksilver Gas Services LP Second Amended and Restated 2007 Equity Plan (filed as Exhibit 10.16 to Quicksilver Gas Services LP's Form 10-K, File No. 001-3363, filed March 15, 2010 and included herein by reference).

Exhibit No.	Sequential Description
+ 10.42	Form of Phantom Unit Award Agreement for Non-Directors pursuant to the Quicksilver Gas Services LP 2007 Equity Plan, as amended (Cash) (filed as Exhibit 10.10 to Quicksilver Gas Services LP's Form S-1/A, File No. 333-140599, filed July 17, 2007 and included herein by reference).
+ 10.43	Form of Phantom Unit Award Agreement for Non-Directors pursuant to the Quicksilver Gas Services LP 2007 Equity Plan, as amended (Units) (filed as Exhibit 10.11 to Quicksilver Gas Services LP's Form S-1/A, File No. 333-140599, filed July 25, 2007 and included herein by reference).
+ 10.44	Quicksilver Gas Services LP Annual Bonus Plan (filed as Exhibit 10.1 to Quicksilver Gas Services LP's Form 8-K, File No. 001-33631, filed December 13, 2007 and included herein by reference).
+ 10.45	Form of Indemnification Agreement by and between Quicksilver Gas Services GP LLC and its officers and directors (filed as Exhibit 10.7 to Quicksilver Gas Services LP's Form S-1/A, File No. 333-140599, filed July 17, 2007 and included herein by reference).
10.46	Asset Purchase Agreement, dated as of May 15, 2009, among Quicksilver Resources Inc., as Seller, and ENI US Operating Co. Inc. and ENI Petroleum US LLC, as Buyers (filed as Exhibit 10.1 to the Company's Form 8-K filed May 19, 2009 and included herein by reference).
10.47	Letter Agreement, dated as of June 15, 2009, among Quicksilver Resources Inc., Quicksilver Resources Canada Inc. and the agents and combined lenders identified therein (filed as Exhibit 10.1 to the Company's Form 8-K filed June 17, 2009 and included herein by reference).
* 21.1	List of subsidiaries of Quicksilver Resources Inc.
* 23.1	Consent of Deloitte & Touche LLP.
* 23.2	Consent of PricewaterhouseCoopers LLP.
* 23.3	Consent of Schlumberger Data and Consulting Services.
* 23.4	Consent of LaRoche Petroleum Consultants, Ltd.
* 23.5	Consent of Netherland, Sewell & Associates, Inc.
* 23.6	Consent of Schlumberger Data and Consulting Services.
* 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.
* 99.1	Report of Schlumberger Data and Consulting Services.
* 99.2	Report of LaRoche Petroleum Consultants, Ltd.
* 99.3	Report of Netherland, Sewell & Associates, Inc.
* 99.4	Report of Schlumberger Data and Consulting Services.

* Filed herewith.

** Excludes schedules and exhibits we agree to furnish supplementally to the SEC upon request.

\+ Identifies management contracts and compensatory plans or arrangements.

SIGNATURES

Pursuant to the requirements of Section 13 of the Securities Exchange Act of 1934, the registrant has duly caused this Annual Report to be signed on its behalf by the undersigned, thereunto duly authorized.

Quicksilver Resources Inc.
(the "Registrant")

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

Dated: March 15, 2010

Pursuant to the requirements of the Securities Exchange Act of 1934, the following persons on behalf of the registrant and in the capacities and on the dates indicated have signed this report below.

Signature	Title	Date
/s/ Thomas F. Darden Thomas F. Darden	Chairman of the Board; Director	March 15, 2010
/s/ Glenn Darden Glenn Darden	President and Chief Executive Officer (Principal Executive Officer); Director	March 15, 2010
/s/ Philip Cook Philip Cook	Senior Vice President – Chief Financial Officer (Principal Financial Officer)	March 15, 2010
/s/ John C. Regan John C. Regan	Vice President, Controller and Chief Accounting Officer (Principal Accounting Officer)	March 15, 2010
/s/ Anne Darden Self Anne Darden Self	Director	March 15, 2010
/s/ W. Byron Dunn W. Byron Dunn	Director	March 15, 2010
/s/ Steven M. Morris Steven M. Morris	Director	March 15, 2010
/s/ Yandell Rogers, III W. Yandell Rogers, III	Director	March 15, 2010
/s/ Mark J. Warner Mark J. Warner	Director	March 15, 2010

QUICKSILVER RESOURCES INC.
2009 Finding and Development Costs
(Unaudited)

The following schedule reflects a reconciliation of 2009 "Finding and Development Costs" (F&D) to the information required by Financial Accounting Standards Codification ("FASC") Topic 932 – Extractive Activities – Oil & Gas. F&D costs are computed by dividing exploration and development capital expenditures for the year, plus asset retirement obligation additions for the year and unevaluated capital expenditures as of beginning of the year, less unevaluated capital expenditures as of end of the year, by reserve additions for the year.

2009 F&D Costs – Dollars in millions, reserves in billions of cubic feet of natural gas equivalent

	Total Proved Reserves	Proved Developed Reserves
Total exploration, development and acquisition capital expenditures	$ 472.1	$ 472.1
Asset retirement obligation additions	1.3	1.3
Adjustments:		
Unevaluated costs as of December 31, 2008	543.5	543.5
Unevaluated costs as of December 31, 2009	(458.0)	(458.0)
Adjusted capital expenditures related to reserve additions	$ 558.9	$ 558.9
Reserve extensions, discoveries, revisions and purchases (Bcfe)	446.8	438.5
Finding & development costs ($/Mcfe)	$ 1.25	$ 1.27

Management believes that providing a measure of F&D costs is useful to assist in an evaluation of Quicksilver's costs, on a per thousand cubic feet of natural gas equivalent basis, to add proved reserves. However, the reader is cautioned that these measures are provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in Quicksilver's financial statements prepared in accordance with GAAP (including the notes thereto). The reader is further cautioned that, due to various factors, including timing differences, F&D costs do not necessarily reflect precisely the costs associated with particular reserves. For example, exploration costs may be recorded in periods prior to the periods in which related increases in reserves are recorded and development costs may be recorded in periods subsequent to the periods in which related increases in reserves are recorded. In addition, changes in commodity prices can affect the magnitude of recorded increases in reserves independent of the related costs of such increases.

As a result of the foregoing factors and various factors that could materially affect the timing and amounts of future increases in reserves and the timing and amounts of future costs, including factors disclosed in Quicksilver's filings with the Securities and Exchange Commission, we cannot assure you that Quicksilver's future F&D costs will not differ materially from those set forth above.

The methods used by Quicksilver to calculate its F&D costs may differ significantly from methods used by other companies to compute similar measures. As a result, Quicksilver's F&D costs may not be comparable to similar measures provided by other companies.

Quicksilver Resources Inc.
Calculation of 2009 Production Replacement Ratio

The production replacement ratio is calculated by dividing the sum of reserve additions from all sources (revisions, extensions and discoveries) for a period by the actual production for the period. Additions to our reserves are proved developed and proved undeveloped reserves. We expect to continue to add to our total proved reserves through these activities, but various factors could impede our ability to do so, including factors disclosed in Quicksilver's filings with the Securities and Exchange Commission. We use the production replacement ratio as an indicator of our ability to replenish annual production volumes and grow reserves. We believe that production replacement is relevant and useful information that is commonly used by parties interested in the oil and gas industry as a means of evaluating the operational performance and prospects of entities engaged in the production and sale of depleting natural resources. However, the reader is cautioned that the production replacement ratio is a statistical indicator that has limitations. As an annual measure, the ratio is limited because it typically varies widely based on the extent and timing of new discoveries and may increase or decrease due to increases or decreases in the prices of the related commodities. Its predictive and comparative value is also limited for the same reasons. In addition, since the ratio does not consider the cost or timing of future production of new reserves, it cannot be used as a measure of value creation. Moreover, the ratio does not distinguish between changes in reserve quantities that are developed and those that will require additional time and funding to develop.

Million cubic feet of natural gas equivalents	
Reserve additions	
Extensions, discoveries & performance revisions	698,434
Pricing revisions	(251,676)
Total additions	446,758
Production	118,452
Production replacement	377%

Quicksilver Resources Inc.
Net Debt per Proved Developed Reserve
(Unaudited)
Dollars in thousands, except per developed reserve

	2009	**2008**
Total debt	$2,427,523	$2,586,045
Less:		
Non-recourse debt of Quicksilver Gas Services LP	125,400	174,900
Marketable securities in Quicksilver Gas Servies LP (1)	426,474	221,255
Marketable securities in BreitBurn Energy Partners L.P. (2)	226,075	150,503
Convertible debentures, net of unamortized discount	136,119	129,239
Net debt	$1,513,455	$1,910,148
Proved developed reserves (Mmcfe)	1,648,302	1,387,047
Net debt per proved developed reserve ($/Mcfe)	$0.92	$1.38

(1) The closing market value of Quicksilver's 17.680 million units, plus asssumed conversion of the note payable into Quicksilver Gas Services' units.

(2) The closing market value of Quicksilver's 21.348 million units.

CORPORATE INFORMATION

DIRECTORS

Thomas F. Darden
Chairman
Glenn Darden
W. Byron Dunn*
Steven M. Morris*
W. Yandell Rogers III*
Anne D. Self
Mark J. Warner*

OFFICERS

Thomas F. Darden
Chairman
Glenn Darden
President & Chief Executive Officer
Jeff Cook
Executive Vice President – Operations
Philip W. Cook
Senior Vice President – Chief Financial Officer
John C. Cirone
Senior Vice President, General Counsel & Secretary
C. Clay Blum
Vice President – Land
Richard C. Buterbaugh
Vice President – Investor Relations & Corporate Planning
John E. Hinton
Vice President – Finance
Vanessa G. LaGatta
Vice President – Treasurer
Stan G. Page
Vice President – U.S. Operations
John C. Regan
Vice President, Controller & Chief Accounting Officer
Anne D. Self
Vice President – Human Resources
Robert N. Wagner
Vice President – Reservoir Engineering

As of March 1, 2010

HEADQUARTERS

777 West Rosedale Street
Fort Worth, Texas 76104
Phone: 817.665.5000
Fax: 817.665.5004
quicksilver@qrinc.com
www.qrinc.com

MAJOR SUBSIDIARIES

Quicksilver Gas Services LP
777 West Rosedale Street
Fort Worth, Texas 76104
Phone: 817.665.8620
Fax: 817.665.5008
www.kgslp.com

Quicksilver Resources Canada Inc.
One Palliser Square
2000, 125-9th Avenue, SE
Calgary, Alberta Canada
T2G 0P8
Phone: 403.537.2455
Fax: 403.262.6115

REGISTRAR AND TRANSFER AGENT

BNY Mellon
480 Washington Blvd.
Jersey City, New Jersey 07310-1900
Phone: 866.637.5420
www.bnymellon.com/shareowner/isd

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

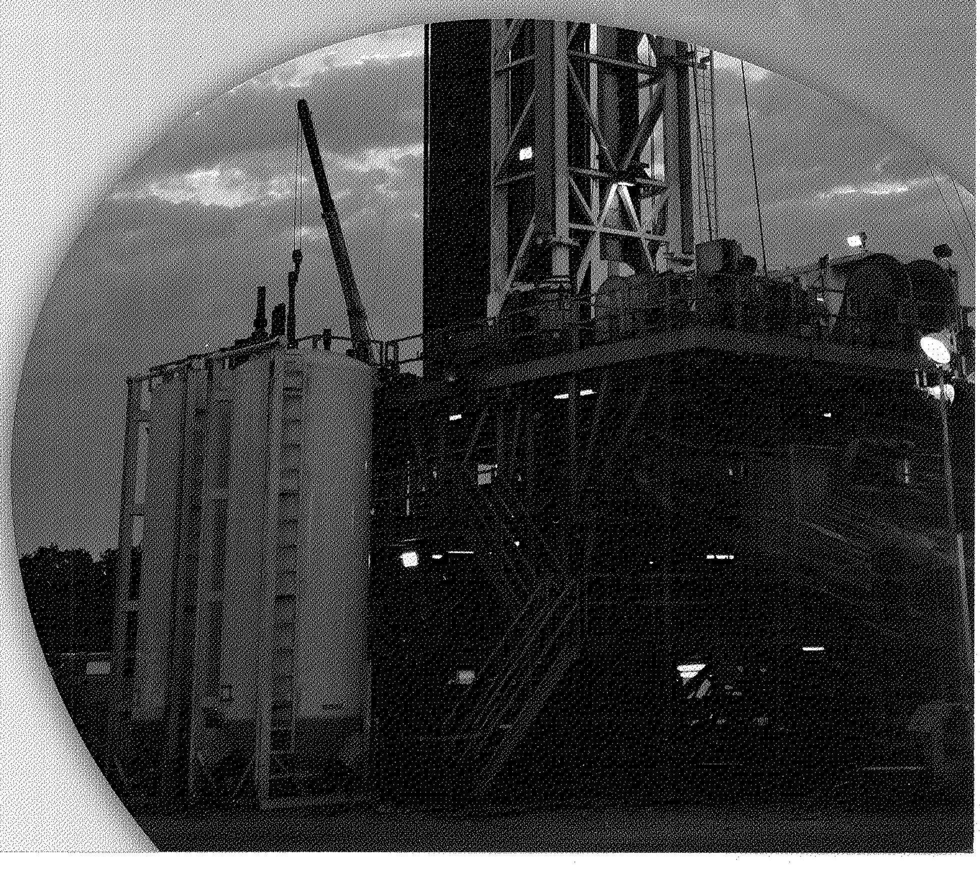
Deloitte & Touche LLP
201 Main Street, Suite 1501
Fort Worth, Texas 76102

ANNUAL MEETING

The Company's Annual Meeting of Stockholders is scheduled for 9:00 am, May 19, 2010
The Fort Worth Club
306 West 7th Street
Fort Worth, Texas

* Member of the Audit; Compensation; Health, Safety and Environmental; and Nominating and Corporate Governance Committees

BACK COVER PHOTO: Quicksilver is building a fleet of CNG powered vehicles for use in its field operations.



QUICKSILVER
RESOURCES

777 West Rosedale Street
Fort Worth, Texas 76104
817.665.5000
www.qrinc.com
NYSE: KWK