QUICKSILVER
RESOURCES

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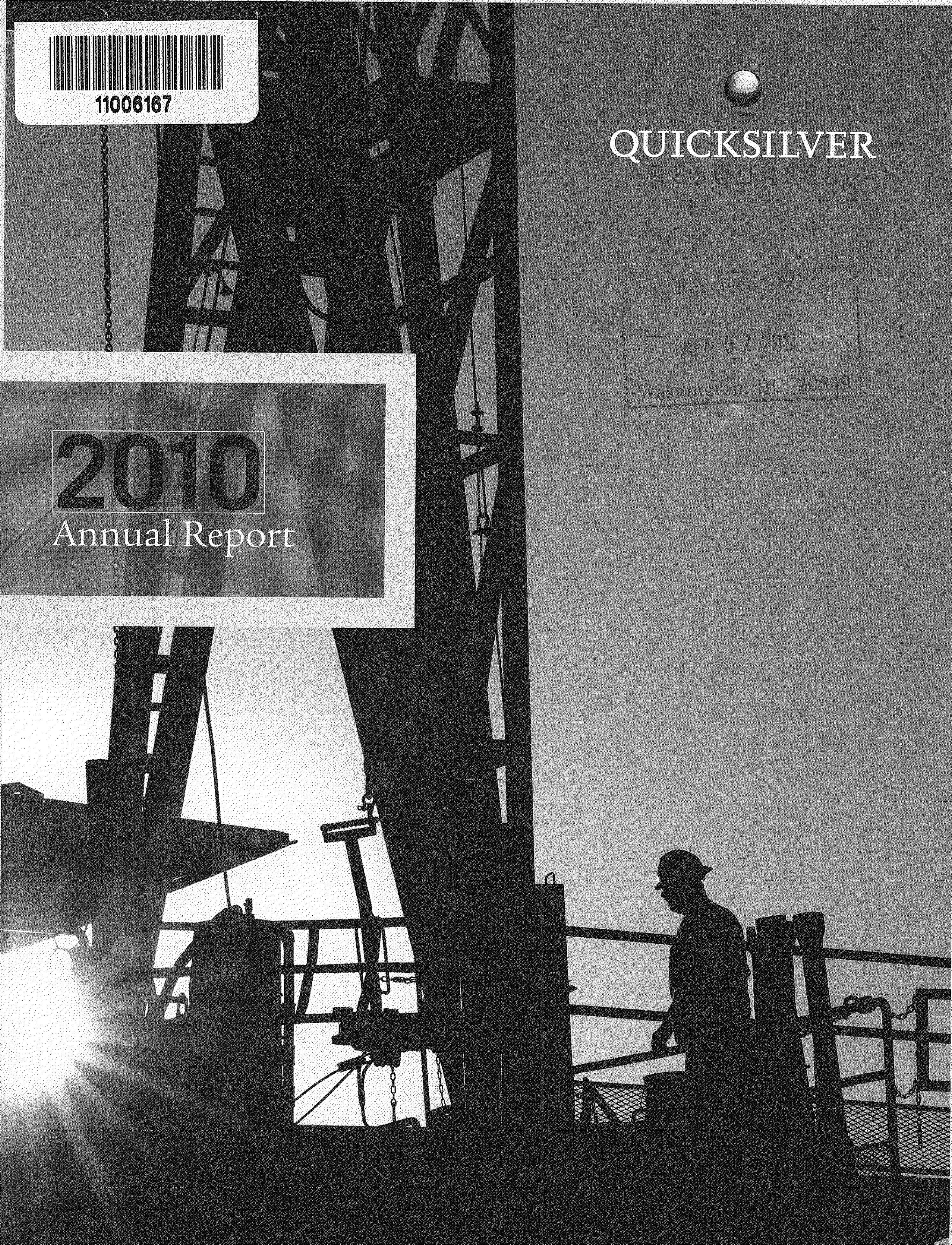
2010 Annual Report



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 gas from shales, coal beds and tight sands. 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, the Green River Basin of north central Colorado and the Southern Alberta Basin of western Montana.

As of December 31, 2010, the company had estimated proved reserves of approximately 2.9 trillion cubic feet of natural gas equivalents, of which 99 percent were natural gas or natural gas liquids and 68 percent were proved developed. As of February 2011, the company also owned approximately 27 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.

COMPANY PROFILE

To Our Shareholders,

OVER THE LAST COUPLE OF YEARS the market for natural gas in this country has been buffeted by both a worldwide recession and an oversupply of product. This combination has created a tough environment to be a gas producer.

Despite these strong headwinds, Quicksilver has continued to build on its stable low-cost platform. In 2010, the company increased reserves 20% year-over-year to 2.9 trillion cubic feet of gas equivalents, of which 68% is classified as proved developed. We replaced 475% of the year's production at an all-in finding, development and acquisition cost of $1.29 per Mcfe. These numbers are among the best in the industry and keep Quicksilver as a leader in low-cost natural gas development. This does not happen by accident, it is cultural. We are an efficient, low-cost operator and it is a competitive advantage.

Quicksilver also had a very good year improving the balance sheet as we reduced total debt by $537 million, resulting in total debt of $0.65 per Mcfe of proved reserve at year end 2010. This debt reduction was achieved primarily through the sale of Quicksilver's interest in the mid-stream entity, Quicksilver Gas Services at an attractive premium. At year-end 2010, all of the company's $1.7 billion long-term debt was in the form of long-term bonds with the earliest maturity in mid 2015.

The current oversupply of natural gas in North America is a function of technology breakthroughs, particularly from hydraulic fracturing in shale formations.Quicksilver and its predecessor company have been doing this for over 20 years. Lots of companies have followed. The distinction that the market is not making (and is well camouflaged by this industry) is which companies actually generate real returns at these low prices.

In the rush to count new production volumes, volumes outweigh profit margins in the eyes of many. This cannot work for long. And of course, in today's world of instant gratification, there is a view that the price of natural gas will never recover.

Our view is this: when the value of the product is below the cost to find and produce it, the model is not sustainable. That is the current situation for many companies in this industry. Not Quicksilver. We also firmly believe that the current BTU disparity between gas and oil is an aberration and will not last. Historically natural gas has traded in the range of 6-10 Mcf to 1 barrel of oil. Today it trades in excess of 20 to 1. We believe this presents a tremendous opportunity to invest in natural gas at the bottom of the cycle.

This wave of new production has made the country very aware of a huge "home grown" domestic supply of energy that can fuel our nation for decades to come. This awareness will turn to action. Quicksilver has some unique advantages to be able to not only survive but to thrive in this environment. In addition to our low cost structure, this company has very few drilling requirements to hold most of our vast inventory of leasehold. Therefore we can manage our capital to stay within cash inflows. A majority of the company's Barnett, Horseshoe Canyon, and southern Alberta Bakken acreage is held by production. In our newest large development area, the Horn River Basin in northeast British Columbia, drilling only three more wells over the next year will convert our 130,000 net acre exploratory license block into 10-year development leases. This project appears to be the largest gas find in the company's history and has the potential to quadruple our current total company reserves. Our product marketing team will continue to search for new markets for our natural gas, targeting direct users and multiple sales point options. In addition we have hedged over 50% of the company's projected natural gas production at close to $6.00 per Mcf for all of 2011, adding predictability to our cash flows.

Although Quicksilver is primarily a producer of natural gas, 24% of our sales come from natural gas liquids and oil. We have several exploratory projects under way that, if successful, will increase that liquids percentage in the total product mix. The largest of which is a project in the Green River Basin targeting oil in the Niobrara Shale. The company will be drilling its first wells this summer to test this exciting play.

Difficult times in the energy industry are not a new phenomenon and in our family history of over 60 years in the business, we have seen many cycles. We do believe that the products we produce and sell are environmentally cleaner and are superior to coal or nuclear to fuel this country's energy needs. Quicksilver has the team, the assets, and the patience to capitalize on this belief.

There is an old saw in the investment business that the public market is a voting mechanism in the short term and a weighing mechanism in the long term. We trust Quicksilver's value will be weighed properly and our long-term view rewarded.

We thank all of the Quicksilver employees and our Board of Directors for their hard work and contributions to this company. We would also like to thank the Quicksilver stockholders for their continued support. We look forward to reporting on Quicksilver's progress and successes in 2011.

Very truly yours,

Glenn Darden
President and Chief Executive Officer

Thomas F. Darden
Chairman of the Board

In millions, except per share, production and product price data	2010	2009	2008	2007	2006
Total revenue	$ 928.3	$ 832.7	$ 800.6	$ 561.3	$ 390.4
Net income (loss) attributable to Quicksilver [a]	$ 435.1	$ (557.5)	$ (378.3)	$ 475.4	$ 90.0
Net income (loss) per diluted share [a] [b]	$ 2.45	$ (3.30)	$ (2.33)	$ 2.87	$ 0.58
Diluted weighted average number of shares outstanding for the periods [b]	178.6	169.0	162.0	168.0	166.3
Total assets	$ 3,512.3	$ 3,612.9	$ 4,498.2	$ 2,773.8	$ 1,881.1
Long-term debt	$ 1,746.7	$ 2,427.5	$ 2,586.0	$ 788.5	$ 887.9
Total equity	$ 1,059.4	$ 696.8	$ 1,211.6	$ 1,192.5	$ 602.1
Natural gas production (Mmcf)	101,664	86,040	68,128	59,619	53,266
Average realized natural gas price per Mcf [c]	$ 6.86	$ 7.42	$ 8.10	$ 6.73	$ 6.05
NGL production (Mmcfe)	26,161	29,860	25,176	14,826	4,476
Average realized NGL price per Mcfe [c]	$ 5.24	$ 4.55	$ 7.57	$ 7.21	$ 6.48
Crude oil production (Mbbl)	303	425	483	584	587
Average realized price per Bbl [c]	$ 71.90	$ 51.85	$ 78.83	$ 63.87	$ 59.99

[a] Net income attributable to Quicksilver and net income per diluted share for 2010 include $303 million and $1.68 per diluted share, respectively, associated with the sale of KGS. 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 L.P. 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 L.P. 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 operations in Michigan, Indiana and Kentucky net of divestiture-related expenses and costs and the loss on related natural gas sales contracts.

[b] Share and per share amounts have been adjusted to reflect a two-for-one stock split during January 2008.

[c] Average realized prices reflect the effect of hedging transactions.

Please refer to the calculations of Finding, Development and Acquisition Cost, Production Replacement Ratio and Total Debt per Proved Reserve that follow the signature page of the Form 10-K.

FINANCIAL HIGHLIGHTS

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, 2010

OR

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

For the transition period from __________ to __________

Commission file number: **001-14837**

QUICKSILVER RESOURCES INC.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**75-2756163** (I.R.S. Employer Identification No.)
801 Cherry Street, Suite 3700, Unit 19, Fort Worth, Texas (Address of principal executive offices)	**76102** (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. (Check one):

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ (Do not check if a smaller reporting company) 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, 2010, the aggregate market value of the registrant's common stock held by non-affiliates of the registrant was $1,296,269,590 based on the closing sale price of $11.00 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, 2011
Common Stock, $0.01 par value per share	171,081,330 shares

DOCUMENTS INCORPORATED BY REFERENCE

Document	Parts Into Which Incorporated
Proxy Statement for the Registrant's May 18, 2011 Annual Meeting of Stockholders	Part III

DEFINITIONS

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

"**ABR**" means alternate base rate
"**AMT**" means alternative minimum tax in the U.S.
"**AOCI**" means accumulated other comprehensive income
"**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
"**Canada**" means our oil and natural gas operations located in Canada
"**DD&A**" means Depletion, Depreciation and Accretion
"**GHG**" means greenhouse gas
"**GPT**" means gathering, processing and transportation expense
"**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
"**MMcfed**" means MMcfe per day
"**NGL**" or "**NGLs**" means natural gas liquids
"**NYMEX**" means New York Mercantile Exchange
"**NYSE**" means New York Stock Exchange
"**OCI**" means other comprehensive income
"**Oil**" includes crude oil and condensate
"**RSU**" means restricted stock unit
"**Tcfe**" means trillion cubic feet of natural gas equivalents

COMMONLY USED TERMS

Other commonly used terms and abbreviations include:

"**Alliance Acquisition**" means the 2008 purchase of Alliance Leasehold and midstream assets in the Alliance airport area of the Barnett Shale
"**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 system and processing facilities purchased by KGS from Quicksilver in January 2010
"**Barnett Shale Asset**" means our operations and our assets in the Barnett Shale located in the Fort Worth Basin of North Texas
"**BBEP**" means BreitBurn Energy Partners L.P.
"**BBEP Unit**" means BBEP limited partner unit
"**CERCLA**" means the Comprehensive Environmental Response, Compensation and Liability Act
"**Crestwood**" means Crestwood Holdings LLC

"**Crestwood Transaction**" means the sale to Crestwood of all our interests in KGS, consisting of 100% of the general partner units, including incentive distribution rights, all of our common and subordinated units and the subordinated note due from KGS

"**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 2009 conveyance of a 27.5% interest in our Alliance Leasehold

"**EPA**" means the U.S. Environmental Protection Agency

"**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 U.S.

"**Gas Purchase Commitment**" means the commitment pursuant to the Eni Transaction to purchase the Eni Production at a fixed price and which expired on December 31, 2010

"**Greater Green River Asset**" means our operations and our assets in the Greater Green River Basin located in Colorado and southern Wyoming

"**HCDS**" means Hill County Dry System, a gas gathering system in Hill County, Texas within the Barnett Shale

"**Horn River Asset**" means our operations and our assets in the Horn River Basin of Northeast British Columbia

"**Horseshoe Canyon Asset**" means our operations and our assets in Horseshoe Canyon, the coalbed methane fields of southern and central Alberta

"**IRS**" means the U.S. Internal Revenue Service

"**KGS**" means Quicksilver Gas Services LP, a publicly-traded partnership, which we formerly owned that traded under the ticker symbol of "KGS" and subsequent to the Crestwood Transaction renamed itself Crestwood Midstream Partners LP and trades under the ticker symbol "CMLP"

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

"**KGS Secondary Offering**" means the public offering of 4,000,000 KGS common units in 2009 and the underwriters' purchase of an additional 549,200 KGS common units in 2010

"**Lake Arlington Project**" means our natural gas leasehold interests in the Lake Arlington area of the Barnett Shale

"**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 2009 under which we agreed to deliver 25 MMcfd at a floor price of $2.49 per Mcf

"**SEC**" means the U.S. 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

"**Southern Alberta Asset**" means our operations and our assets in the Southern Alberta Basin of northern Wyoming and Montana, including our Cutbank field operations and assets

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For the Year Ended December 31, 2010

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;
- failure to receive a proposal for a transaction to pursue strategic alternatives for us or that any transaction will be approved or consummated;
- costs and expense associated with our consideration of potential strategic alternatives, including without limitation, any related litigation expense; 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

We are a Fort Worth-based independent oil and gas company engaged primarily in the acquisition, exploration, development, exploitation and production of natural gas, NGLs and oil onshore in North America. 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 own producing oil and natural gas properties in the U.S., principally in Texas, Colorado, Wyoming and Montana, and in Canada in Alberta and British Columbia. We have total proved reserves of more than 2.9 Tcfe at December 31, 2010. Our development and production areas include the following regions:

- the Barnett Shale;
- the Cutbank Field in the Southern Alberta Basin, and
- Horseshoe Canyon.

We also have significant exploration activities in North America, most notably in the following regions:

- Horn River Basin;
- Greater Green River Basin, and
- Southern Alberta Basin.

In addition, our new ventures team actively studies other basins in North America which may yield future exploration opportunities. As of December 31, 2010, we also own 29% 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. BBEP Units are traded on NASDAQ 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 February 16, 2011, members of the Darden family and entities controlled by them, beneficially own approximately 32% of our outstanding common stock.

STRATEGIC TRANSACTIONS IN THE LAST FIVE YEARS

In October 2010, we sold all of our interests in KGS to Crestwood. We received $700 million in cash, net of transaction costs, and recognized a gain of $473 million. We believe the sale of these midstream assets allowed us to better focus on the development of our natural gas properties while redeploying the associated capital into projects with higher expected returns.

In May 2010, we acquired an additional 25% working interest in the Lake Arlington Project that was previously owned by our partner, representing 125 Bcf of proved reserves, for $62 million in cash and 3.6 million BBEP Units.

In January 2010, we completed the sale of our Alliance Midstream Assets to KGS for $95 million. KGS funded the purchase primarily with proceeds from the KGS Secondary Offering which reduced our ownership in KGS from 73% to 61%.

In June 2009, we completed the sale of a 27.5% working interest in our Alliance Leasehold representing 121 Bcf of proved reserves to Eni for $280 million. In addition to the Alliance Leasehold, which then included approximately 13,000 acres in the Barnett Shale, we 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.

In December 2008, we sold the gathering system in our Lake Arlington Project to KGS for $42 million.

In August 2008, we completed the $1.3 billion Alliance Acquisition that consisted of producing and non-producing leasehold, royalty and midstream assets in the Barnett Shale. Consideration in the transaction was $1 billion in cash and $262 million of our common stock. We funded the cash portion of the transaction by incurring additional debt.

In 2007, we sold all of our oil and gas properties in Michigan, Indiana and Kentucky to BBEP for $750 million in cash and 21.3 million BBEP Units, valued at $724 million at the closing of the transaction.

BUSINESS STRATEGY

We have a multi-pronged strategy to increase share value through cost-effective growth in production and reserves by focusing on unconventional resource 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 reservoirs. 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 technical expertise. We currently have two core development areas, the Barnett Shale and Horseshoe Canyon, where we have a large inventory of repeatable, low-risk projects. In 2011, we expect to concentrate our development drilling primarily on our Barnett Shale Asset.

Pursue disciplined organic growth opportunities: We typically plan to spend 10% of our capital program on high-potential, longer cycle-time exploration projects to replenish our inventory of development projects for the future. Through our activities in multiple unconventional resource basins, we have significant expertise and a demonstrated history of identifying, developing and producing fractured shales, coal seams and tight sands. We are focused on identifying and evaluating additional opportunities that allow us to apply this expertise and experience to the development and operation of other unconventional reservoirs in North America. In 2011, we will continue to focus our exploratory activities on our Horn River Asset, where we hold exploratory licenses covering more than 130,000 net prospective acres, and in our Greater Green River Asset, where we hold approximately 150,000 net acres. We also expect to pursue new potential horizons on our existing acreage in our Horn River Asset and Southern Alberta Asset. We may also seek to acquire similar acreage positions for future exploration activities.

Enhance profitability through control and marketing of our equity natural gas and oil: We generally 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 during the infrastructure's development phase. 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. In 2011, we expect to deploy capital to begin construction of midstream assets for our Horn River Asset. While the Crestwood Transaction caused a decrease in our control of the midstream operations in the Barnett Shale, the backbone of the infrastructure is in place and has been built to our design and the proceeds from this transaction enabled us to significantly improve our capital structure.

Maintain flexible financial profile: We believe that a flexible financial structure enables us to capitalize on opportunities and to limit our financial risk. For example, our BBEP Units provide us with additional financial flexibility while enabling us to participate in BBEP's expected growth in market value. In addition, to increase the predictability of the prices we receive for our natural gas and NGL production, we hedge the commodity price of a substantial portion of our expected 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. Further, we may enter into long-term hedges to provide such predictability over longer periods.

BUSINESS STRENGTHS

High-quality asset base with long reserve life: Our proved reserves totaled more than 2.9 Tcfe as of December 31, 2010 and 68% were proved developed. Our Barnett Shale Asset has 90% of our proved reserves and 9% are located in our Horseshoe Canyon Asset. These areas have long histories of proven well performance and have established infrastructure to deliver our production to sales markets. We believe our reserves are characterized by long lives and predictable well production profiles. Based on our annualized fourth-quarter 2010 average production from these properties, our implied reserve life (proved reserves divided by annualized fourth-quarter 2010 production) was 20.4 years and our implied proved developed reserve life (proved developed reserves divided by annualized fourth-quarter 2010 production) was 13.8 years. As of December 31, 2010, 97% of our proved reserves are from properties we operate.

Multi-year inventory of development and exploitation drilling projects: As of December 31, 2010, we owned leases covering more than 470,000 net acres in our two core areas, of which 78% were classified as held by production which reflects 93% and 46% of our net acreage held by production in Horseshoe Canyon and the Barnett Shale, respectively. Within our Barnett Shale Asset alone, we have identified approximately 800 remaining drilling locations which provide us with more than a 10-year inventory of drilling locations at the 2011 anticipated drilling rate. 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 Barnett Shale.

We have also identified exploratory opportunities that provide meaningful exposure to additional oil and gas resources. As of December 31, 2010, we have successfully drilled and completed four wells in our Horn River Asset. Our total recognized reserves in our Horn River Asset are 16.4 Bcfe. At December 31, 2010, 37% of our licensed acreage has been validated and 3% of our licensed acreage is held by production. After completing our planned 2011 exploratory activities in the Horn River Basin, we expect to have 80% of our license acreage validated.

Proven record of organic growth in reserves and production: During the past three years, our proved reserves have grown 88% as we added 1.4 Tcfe of proved reserves from organic development activities. We supplemented this activity with acquisitions in the Barnett Shale and Horseshoe Canyon, which combined, total 447 Bcf of acquired proved reserves. We also sold 121 Bcf of proved reserves in the Eni Transaction in 2009. We have organically replaced 398% of our production during the three years ended December 31, 2010. Our growth has resulted from our ability to acquire attractive undeveloped acreage and to 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 provides opportunities to continue our organic growth of reserves and production.

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 with us 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 reservoirs. Our executive management team is supported by a core team of technical, operational and financial managers who have significant industry experience, including experience in drilling and completing horizontal wells in unconventional reservoirs and in strategic transactions.

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. In addition, we expect to develop midstream assets, including gathering and treating systems in the Horn River Basin. We also indirectly own interests in other oil and natural gas properties through our ownership of approximately 29% of BBEP as of December 31, 2010.

OIL AND NATURAL GAS OPERATIONS

Our oil and natural gas operations are focused onshore in North America, primarily in plays containing unconventional reservoirs. Our current production and development operations are concentrated in our two core areas: the Barnett Shale and Horseshoe Canyon. At December 31, 2010, we had total proved reserves of more than 2.9 Tcfe, of which 76% were natural gas and 23% were NGLs. For 2010, we had average production of 355.2 MMcfed based upon our total production of 129.6 Bcfe. Since going public in 1999, we have grown our reserves and production at an approximate compound annual growth rate of 23% and 18%, respectively.

We believe development of our leasehold interests in our core area in the Barnett Shale and our exploration activities in the Horn River Basin and the Greater Green River Basin will drive our 2011 and 2012 reserve and production growth. We may also pursue acquisitions of additional interests, which could allow for further capitalization on our proven expertise in unconventional resource plays. Details of our 2011 capital program and our projected production levels can be found in Item 7 of this Annual Report.

Texas

Our Barnett Shale Asset contains 90% of our total proved reserves and had 79% of our total average daily production in 2010. In the fourth quarter of 2010, our net production from our Barnett Shale Asset wells was 309.2 MMcfed. We expect 84% of our 2011 production to come from our Barnett Shale Asset.

At December 31, 2010, our Barnett Shale Asset includes more than 155,000 net acres of which approximately 46% is currently held by production. Much of our acreage in Hood and Somervell counties contains high-Btu natural gas. NGLs, within a high-Btu natural gas stream, are extracted through a midstream system that we developed and is now owned by a third party. In the current pricing environment where NGLs trade at a premium to methane, we are able to increase our revenue per Mcf of natural gas production by extracting and separately selling NGLs.

During 2010, we drilled 99 (82.0 net) wells in our Barnett Shale Asset primarily from multi-well drilling pads. On these multi-well pads, all the wells are drilled prior to initiating completion activities. At December 31, 2010, we had drilled a total of 973 (809.5 net) wells in our Barnett Shale Asset since we began exploration and development operations in 2003. In 2010, we completed 163 gross (119.3 net) wells and brought online 144 (101.0 net) wells, which gives us a remaining gross inventory of drilled-but-uncompleted wells of 121 (109.9 net) at December 31, 2010. At December 31, 2010, we had three drilling rigs operating in our Barnett Shale Asset, but we expect to utilize only two rigs in this area during most of 2011.

Rocky Mountain Region

Our Rocky Mountain assets are located in the Southern Alberta Basin and the Greater Green River Basin. Production from our Southern Alberta Asset is primarily oil from depths ranging from 1,000 feet to 17,000 feet. We have approximately 175,000 net acres in our Southern Alberta Asset, 60% of which are held by production. At December 31, 2010, proved reserves from these properties were 2.7 MMBbls of oil and NGLs and 0.9 Bcf of natural gas for total equivalent reserves of 17.0 Bcfe.

We also hold approximately 150,000 net acres in the Greater Green River Basin where we are currently conducting exploratory activities and have two producing wells. Total proved reserves in our Greater Green River Basin Asset are 0.3 Bcfe at December 31, 2010.

Daily production from all our properties in the Rocky Mountain region averaged 4.0 MMcfed for 2010.

Canada

At December 31, 2010, Canadian proved reserves were 266 Bcfe, of which 94% were attributable to our Horseshoe Canyon Asset. Canadian production averaged 69.2 MMcfed, representing 19% of our total 2010 production. Production from all Canadian properties averaged 76.5 MMcfed during the fourth quarter of 2010 due to new wells brought online in our Horn River Asset and a minor acquisition of additional producing properties in Horseshoe Canyon.

In Horseshoe Canyon, as of December 31, 2010, we had approximately 38,000 (21,000 net) undeveloped acres. During 2010 we spent $14.2 million for the drilling of 14 (9.9 net) productive wells and brought online 54 (36.6 net) wells. During 2011, we expect to drill and complete 29 (23 net) wells, and similar to 2010, we expect to completely fund these activities with operating cash flows from our Horseshoe Canyon Asset.

We also have exploratory licenses with working interests in more than 130,000 net acres in the Horn River Basin. During 2010, we spent $57.9 million for drilling and completion costs on our Horn River Asset where we drilled and cased three wells and completed two wells. As of December 31, 2010, we had four wells producing and one well drilled and awaiting completion in the Horn River Basin. We have gathering and processing contracts in the Horn River Basin that run until 2018. Volume under these contracts began at 3 MMcfd and ultimately increases to 100 MMcfd. We also have transportation contracts in place that span from 2012 to 2017. Transportation volume under the contracts begins at 30 MMcfd and ultimately increases up to 54 MMcfd. Our total proved reserves in our Horn River Asset were 16.4 Bcfe as of December 31, 2010.

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 2010 and 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 2010 and 2009 are presented in compliance with the new rule. Our 2008 proved reserve estimates and related disclosures were prepared in compliance with the SEC guidance then in effect.

The process of estimating natural gas, NGLs 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 - 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 - Engineering has over 15 years experience in the oil and gas industry. The 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 reserve additions and revisions and prepares internal proved reserve estimates. In addition, they are responsible for maintaining all reserve engineering data. Integrity of reserve engineering data is enhanced by restricting full access to only the members of our reservoir engineering team. Limited other personnel have read-only access with no ability to modify reserve engineering data.

Our U.S. and Canadian 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 fractured shales, coalbeds and tight sands. Prior to finalizing their reserve estimates, the independent petroleum engineers' results are reviewed in detail by our internal reservoir engineering team. Reports of our proved reserves prepared by these independent petroleum engineers have been reviewed by our Vice President - Engineering and executive management team.

The Audit Committee of our Board of Directors meets with executive management, our Vice President - Engineering and the independent petroleum engineers to discuss the process and results of reserve estimation. Our analytical review of reserve estimates includes comparisons of our ending proved undeveloped estimates to our average ending ultimate recoverable reserves for each of our operating areas and sub-areas. We also conduct 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" connotes 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 repeatability. 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. Proved reserves for undrilled wells are estimated only where it can be demonstrated that there is continuity of production from the existing productive formation. To achieve reasonable certainty of our proved reserve estimates, our reservoir engineering team assumes continued use of technologies with demonstrated success of yielding expected results, including the use of drilling results, well performance, well logs, seismic data, geologic maps, well stimulation techniques, well test data, and reservoir simulation modeling.

The proved reserve data we disclose are 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 estimating our proved oil and gas reserves may be found in Item 1A of this Annual Report.

The following table summarizes our proved reserves at December 31, 2010 and 2009 in accordance with the rule recently established by the SEC. Our estimates of proved oil and gas reserves at December 31, 2008 were prepared in compliance with SEC requirements then in effect.

	Proved Developed Reserves For the Years Ended December 31,			Proved Undeveloped Reserves For the Years Ended December 31,			Total Proved Reserves For the Years Ended December 31,		
	2010	2009	2008	2010	2009	2008	2010	2009	2008
Natural gas (MMcf)									
U.S.	1,312,777	1,044,140	756,191	628,946	511,894	550,306	1,941,723	1,556,034	1,306,497
Canada	242,941	223,300	278,668	22,947	29,753	53,903	265,888	253,053	332,571
Total	1,555,718	1,267,440	1,034,859	651,893	541,647	604,209	2,207,611	1,809,087	1,639,068
NGL (MBbl)									
U.S.	64,908	60,997	56,181	47,536	37,264	35,746	112,444	98,261	91,927
Canada	12	13	8	-	-	-	12	13	8
Total	64,920	61,010	56,189	47,536	37,264	35,746	112,456	98,274	91,935
Oil (MBbl)									
U.S.	2,775	2,467	2,509	533	392	405	3,308	2,859	2,914
Canada	-	-	-	-	-	-	-	-	-
Total	2,775	2,467	2,509	533	392	405	3,308	2,859	2,914
Total (MMcfe)									
U.S.	1,718,875	1,424,924	1,108,331	917,357	737,830	767,212	2,636,232	2,162,754	1,875,543
Canada	243,017	223,378	278,716	22,947	29,753	53,903	265,964	253,131	332,619
Total	1,961,892	1,648,302	1,387,047	940,304	767,583	821,115	2,902,196	2,415,885	2,208,162

	Years Ended December 31,		
	2010	2009	2008 (1)
Representative prices:			
Natural gas – Henry Hub	$ 4.38	$ 3.87	$ 5.71
Natural gas – AECO	4.08	3.76	5.44
NGL – Mont Belvieu, Texas	37.56	24.94	21.65
Oil – WTI Cushing	79.43	61.18	44.60
Standardized measure of discounted future net cash flows (2), after income tax (in millions)	$ 1,788.2	$ 1,182.7	$ 1,794.3

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

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

PROVED UNDEVELOPED RESERVES

Our 2010 drilling and completion activities related to our proved undeveloped locations as of December 31, 2009 were as follows:

	For the Year Ended December 31, 2010					
	Drilled		Completions		Producing	
	Gross	Net	Gross	Net	Gross	Net
Barnett Shale	43.0	38.1	29.0	25.5	27.0	23.5
Horseshoe Canyon	4.0	3.3	4.0	3.3	2.0	1.3
Total	47.0	41.4	33.0	28.8	29.0	24.8

Costs incurred in 2010 relating to the drilling and completion activities related to our proved undeveloped locations as of December 31, 2009 were $99.3 million.

Our gross capital costs for a Barnett Shale Asset well from preparation of the multi-well drilling pad through the initiation of production generally range from $2.5 million to $6.5 million depending on factors such as the area, the depth and lateral length of each well, number of stages of fracture stimulation 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.

In Horseshoe Canyon, the gross capital costs for a typical well from pre-drilling preparation through the initiation of production generally range from $0.2 million to $0.3 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.

In the Horn River Basin, we are still in the exploratory phase and costs are higher than we anticipate them to be in full development. In full development, we expect gross capital costs per well from preparation of the multi-well drilling pad through the initiation of production generally to range from $7 million to $8 million depending on factors such as the depth and lateral length of each well, number of stages of fracture stimulation and its distance to central facilities.

As of December 31, 2010, we had total proved undeveloped reserves of 940.3 Bcfe primarily comprised of 917.4 Bcfe in our Barnett Shale Asset on 360 well locations and 22.9 Bcfe in our Horseshoe Canyon Asset on 165 well locations. All of the 525 well locations are scheduled for development before the end of 2015.

Regionally, we estimate that our proved undeveloped well locations will be developed on the following timeline:

	Barnett Shale	Horseshoe Canyon	Total
2011	44	-	44
2012	66	38	104
2013	111	61	172
2014	89	60	149
2015	50	6	56
Total	360	165	525

During 2011, we expect to spend $227.1 million to drill, complete and tie-in wells on proved locations. Estimated future development costs on proved locations as of December 31, 2010 are projected to be $215.5 million for 2012, $286.3 million for 2013, $321.1 million for 2014, $192.7 million for 2015.

At December 31, 2010, none of our inventory of proved undeveloped drilling locations has been recognized as proved reserves for five years or longer. Currently, we anticipate that our proved undeveloped reserves will be developed within five years.

Proved undeveloped reserves in our Barnett Shale Asset have increased 24% from 2009 due to drilling results in areas that we had no or limited proved undeveloped well locations at December 31, 2009 and that resulted in the first recognition of proved undeveloped reserves on offset locations, plus acquisitions of additional acreage at our Lake Arlington Project and Alliance Leasehold.

DEVELOPMENT AND EXPLORATION ACTIVITIES AT YEAR END

At December 31, 2010, we had three drilling rigs operating in our Barnett Shale Asset, including two rigs operating on proved undeveloped locations and one rig operating on an unproved location. Additionally, completion work was in progress on 60 proved wells in our Barnett Shale Asset, with 121 (109.9 net) wells awaiting completion or tie-in to sales lines.

One drilling rig was operating on an unproved location in our Horn River Asset and 154 wells (105.8 net) in our Horseshoe Canyon Asset 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,					
	2010		2009		2008	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Development:						
U.S.						
Productive [1]	97.0	80.5	154.0	93.2	292.0	255.7
Non-productive	2.0	1.5	-	-	1.0	1.0
Canada						
Productive [2]	18.0	9.9	141.0	36.1	372.0	155.9
Non-productive	-	-	-	-	1.0	1.0
Total	117.0	91.9	295.0	129.3	666.0	413.6
Exploratory:						
U.S.						
Productive	-	-	4.0	4.0	5.0	4.1
Non-productive	-	-	-	-	2.0	2.0
Canada						
Productive	2.0	2.0	2.0	2.0	-	-
Non-productive	-	-	-	-	-	-
Total	2.0	2.0	6.0	6.0	7.0	6.1
Total:						
Productive	117.0	92.4	301.0	135.3	669.0	415.7
Non-productive	2.0	1.5	-	-	4.0	4.0
Total	119.0	93.9	301.0	135.3	673.0	419.7

(1) U.S. development drilling includes non-operated drilling of 3 wells (0.4 net), 37 wells (3.0 net) and 36 wells (16.1 net) for 2010, 2009 and 2008, respectively.

(2) Canadian development drilling includes non-operated drilling of 7 wells (0.4 net), 88 wells (8.1 net) and 170 wells (15.3 net) for 2010, 2009 and 2008, respectively.

VOLUME, SALES PRICES AND OIL AND GAS PRODUCTION EXPENSE

The discussion of volume 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 contracts with third parties that require we provide minimum daily natural gas or NGL volume for gathering, fractionation and transportation, as determined on a monthly basis, or pay for any deficiencies at a specified reservation fee rate. We believe our available supply, including royalty volume and other third-party volume, will satisfy the required volume under the commitments below.

	Total	2011	2012	2013	2014	2015	Thereafter
				(In thousands)			
Gathering							
Barnett Shale	$ 11,981	$ 2,281	$ 2,288	$ 2,281	$ 2,281	$ 2,281	$ 569
Horn River	96,683	7,220	12,146	16,451	16,131	13,557	31,178
Processing and Fractionation							
Barnett Shale	22,785	7,588	7,609	7,588	-	-	-
Horn River	120,450	4,127	11,515	17,973	19,732	20,336	46,767
Transportation							
Barnett Shale	129,089	19,571	20,196	18,378	15,715	15,468	39,761
Horseshoe Canyon	8,344	3,528	3,163	1,623	10	10	10
Horn River	24,972	-	2,088	4,686	5,467	5,467	7,264
Total GPT obligations	$ 414,304	$ 44,315	$ 59,005	$ 68,980	$ 59,336	$ 57,119	$ 125,549

We have dedicated substantially all natural gas production from our Barnett Shale Asset for gathering and compression to KGS through 2020. The rates charged by KGS are fixed for each system but vary by system and range from \$0.71 to \$0.74 per Mcf of gathered volume but are subject to annual inflationary increases. Processing fees are fixed at \$0.54 per Mcf, but are also subject to annual inflationary increases. We are not obligated to guarantee KGS any minimum volume.

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 2010, Louis Dreyfus Natural Gas Corp and Targa Liquids Marketing and Trade, the largest purchasers of our products, accounted for 17% and 12% of our total natural gas, NGL and oil sales, respectively.

ACQUISITION, EXPLORATION AND DEVELOPMENT CAPITAL EXPENDITURES

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

	U.S.	Canada	Consolidated
		(In thousands)	
2010			
Proved acreage	$ 125,647	$ 19,271	$ 144,918
Unproved acreage	44,271	827	45,098
Development costs	378,056	14,182	392,238
Exploration costs	9,385	57,896	67,281
Total	$ 557,359	$ 92,176	$ 649,535
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

PRODUCTIVE OIL AND GAS WELLS

The following table summarizes productive wells:

	As of December 31, 2010			
	Natural Gas		Oil	
	Gross	Net	Gross	Net
U.S.	977.0	807.4	198.0	194.0
Canada	2,861.0	1,401.7	2.0	0.1
Total	3,838.0	2,209.1	200.0	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 are not 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, 2010			
	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
Barnett Shale	80,353	71,850	104,792	83,649
Other Texas	2,432	2,234	144,921	106,154
Greater Green River Basin	7,439	4,687	182,908	143,849
Southern Alberta Basin	110,990	103,776	87,366	71,724
U.S.	201,214	182,547	519,987	405,376
Horseshoe Canyon	470,123	295,083	38,021	21,087
Horn River Basin	3,900	3,900	152,897	152,897
Canada	474,023	298,983	190,918	173,984
Total	675,237	481,530	710,905	579,360

The following table summarizes information regarding the total number of net undeveloped acres as of December 31, 2010:

		2011 Expirations		2012 Expirations		2013 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	189,803	52,097	998	19,203	144	12,752	552
Rockies	215,573	28,797	5,308	17,956	388	29,357	3,817
Canada	173,984	34,428	1,701	66,637	359	4,994	–
Total	579,360	115,322	8,007	103,796	891	47,103	4,369

All of the acreage scheduled to expire can be held through drilling and producing operations. We believe that we have the ability to retain substantially 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 team 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 subject to sanctions, including 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. 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, curtail our operations, or otherwise increase our compliance costs.

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 have been implemented or are under development, or further investigate the environmental impacts of, hydraulic fracturing. In particular, the EPA has commenced a study to determine the environmental and health impacts of hydraulic fracturing. Such initiatives could require us or third parties, including our service providers, 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 implement a GHG recordkeeping and reporting program due to issuance of the EPA's subpart W regulation which will require significant effort to quantify sources at all of our production sites, and beginning in 2012, we will be required to report our GHG emissions from operations. In addition, the EPA has begun regulating GHG emissions from stationary sources pursuant to the Prevention of Significant Deterioration and Title V provisions of the federal Clean Air Act, as a result of which we might be required to obtain permits to construct, modify or operate facilities on account of, and implement emission control measures for, our GHG emissions. Also, regulatory authorities are considering, or have developed, energy or emission measures to reduce GHG emissions. Any limitation, or further 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 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 for free 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, 2011, we had 452 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, 2011.

Name	Age	Position(s)
Thomas F. Darden	57	Director, Chairman of the Board
Glenn Darden	55	Director, President and Chief Executive Officer
Anne Darden Self	53	Director, Vice President - Human Resources
Jeff Cook	54	Executive Vice President - Operations
Philip W. Cook	49	Senior Vice President - Chief Financial Officer
John C. Cirone	61	Senior Vice President and General Counsel
Stan Page	53	Senior Vice President - U.S. Operations
John C. Regan	41	Vice President, Controller and Chief Accounting Officer
Chris M. Mundy	38	Vice President - Engineering
John D. Rushford	50	Senior Vice President and Chief Operating Officer - Quicksilver Resources Canada Inc

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 has served as a director of Crestwood Gas Services GP LLC (formerly known as Quicksilver Gas Services GP LLC) since 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 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). He served as a director of Crestwood Gas Services GP LLC (formerly known as Quicksilver Gas Services GP LLC) from March 2007 to October 2010.

ANNE DARDEN SELF has served on our Board of Directors since August 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 executive capacities with 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 and General Counsel in January 2006, after serving as our Vice President and General Counsel since July 2002. Mr. Cirone served as our Secretary from July 2002 to November 2010. 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.

STAN PAGE became our Senior Vice President - U.S. Operations in June 2010, after serving as our Vice President - U.S. Operations since October 2007. Mr. Page joined us from BP America (formerly known as Amoco Production Company) where he held various management positions of increasing responsibility from 1979 to 2007, including Operations Center Manager for East Texas Operations from 2005 to 2007.

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.

CHRIS M. MUNDY became our Vice President - Engineering responsible for corporate reserves in August 2010 after serving as our Senior Director - Engineering from January 2010 to August 2010, Director - Engineering from May 2009 to January 2010 and Manager, Engineering from October 2008 to May 2009. Mr. Mundy previously served as Manager, Corporate Projects for Quicksilver Resources Canada Inc. where he led the Horseshoe Canyon development program and was responsible for project planning and budgeting from September 2004 to September 2006. Prior to re-joining us in 2008, Mr. Mundy served as Manager, Engineering at Twin Butte Energy where he was responsible for corporate reserves and numerous acquisition and divestiture evaluations from September 2006 to October 2008.

JOHN D. RUSHFORD became Senior Vice President and Chief Operating Officer of Quicksilver Resources Canada Inc. in August 2010. He is a Professional Engineer with more than 25 years of oil and gas experience in project development and business unit management. Mr. Rushford joined us from Cenovus Energy Inc. where he served as the Vice President of Business Services supporting Cenovus' business unit operations from 2005 to 2010. Prior to Cenovus he had more than 15 years of increasingly senior management positions at PanCanadian Petroleum Ltd. and EnCana Corp., including Vice President of the Chinook Business Unit that commercialized coalbed methane in Canada and as Vice President of the Fort Nelson Business Unit.

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 between 2008 and 2010. 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;
- the quantity of natural gas in storage;
- weather conditions;
- domestic and foreign governmental regulations;
- impact of trade organizations, such as OPEC;
- political conditions in oil, NGLs and natural gas producing regions;
- speculation by investors in oil and natural gas; 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 which, among other things, imposes limits to the capitalized cost for each country. Each capitalized cost pool cannot exceed the net present value of the underlying natural gas, NGL and oil reserves. We recognized impairment to the carrying value of our oil and gas properties in each of the three years ended December 31, 2010 and could recognize future impairments if natural gas, NGL or oil prices utilized in determining reserve value 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 the timing and amount 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 addition 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 expense 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, 2010, 32% of our 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 specifications, 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 proved natural gas and oil reserves. In accordance with SEC requirements, the 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 specified by the SEC, 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.

Our Barnett Shale Asset and Horseshoe Canyon Asset account for 79% and 17% of our 2010 production, respectively. 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 and compliance with U.S. and Canadian laws and regulations, such as the U.S. Foreign Corrupt Practices Act. 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 U.S. 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 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 insured or 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. 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 operations 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. Even in the event that our exploration and development projects do result in meaningful additional commercially viable reserves, midstream infrastructure may not exist or may not be constructed, either of which could adversely impact our ability to benefit from those reserves. If our exploration and development efforts are unsuccessful, our leases covering acreage that is not already held by production could expire. If they do expire and if we are unable to renew the leases on acceptable terms, we will lose the right to conduct drilling activities and the resulting economic benefits associated therewith. Furthermore, while our revenue may increase if prevailing petroleum prices increase materially, our finding and operating costs also could increase.

We have risk through our investment in BBEP.

As of December 31, 2010, we owned an approximate 29% interest in BBEP through our ownership of BBEP Units, 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. In 2009, BBEP suspended distributions and did not resume distributions until the distribution for the first 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 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 Units. We recognized impairment to the carrying value of our BBEP Units in the fourth quarter of 2008 and the first quarter of 2009, and we could recognize future impairments 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.

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. The marketability of our production depends in part on the availability, proximity and capacity of pipeline systems owned by third parties. A portion of our production could be interrupted, or shut in, from time to time for numerous reasons, including as a result of weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, maintenance of third-party facilities or capital constraints that limit the ability of third parties to construct gathering systems, processing facilities or interstate pipelines to transport our production. Disruption of our production could negatively impact our ability to market, fractionate and deliver our production. 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, or if further planned development of such assets is delayed or abandoned, 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 hydrocarbon price fluctuations, we have entered into financial hedging arrangements which may limit the benefit we would receive from increases in hydrocarbon 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. Regulators 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. For example, GHG emission regulation is becoming more stringent. We are currently required to report annual GHG emissions from certain of our operations, and additional GHG emission related requirements have been implemented or are in various stages of development. The EPA has begun regulating GHG emissions from stationary sources pursuant to the federal Clean Air Act, as a result of which we might be required to obtain permits to construct, modify or operate facilities on account of, and implement emission control measures for, our GHG emissions. Also, regulatory authorities are considering, or have developed, energy or emission measures to reduce GHG emissions for oil and gas operations. Any limitation of, or further 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 have been implemented, or are under development to 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. In particular, the EPA has commenced a study to determine the environmental and health impacts of hydraulic fracturing. 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 proved reserves, 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. 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 expense, 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 11 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.

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.

As of February 16, 2011, members of the Darden family, together with entities controlled by them, beneficially own approximately 32% of our outstanding common stock. 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 170 million shares of our common stock outstanding at December 31, 2010. 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, 2010, 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 3.3 million shares of our common stock at December 31, 2010.

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 volume, 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.

The absence of an acquisition proposal would likely have an adverse impact on the market price of our common stock.

On October 18, 2010, we announced that our Board of Directors had received a letter from Quicksilver Energy, L.P., an entity controlled by members of the Darden family, indicating that a group of investors consisting of Quicksilver Energy, L.P. and members of the Darden family (the "Darden Investor Group") is interested in exploring strategic alternatives for us, which might include a "take private" transaction. On the last trading day prior to this announcement, our common stock closed at $12.61 per share. At the closing on the day of the announcement, the stock price had risen to $14.65 per share. On February 2, 2011, the Darden Investor Group publicly indicated that it had confidence in the executability of a transaction that valued our common stock at a price in excess of $16 per share and would be interested in submitting a proposal subject to certain conditions described in its February 1, 2011 letter to our Board of Directors. On February 23, 2011, we amended our Amended and Restated Rights Agreement in connection with a request from the Darden Investor Group. The amendment permits the Darden Investor Group to engage in discussions with a potential co-investor regarding a possible acquisition of the Company. If no proposal is forthcoming from the Darden Investor Group or from any other potential acquirer, the stock price might retreat from its current trading range. There can be no assurance that any proposal for a transaction will be received or that any transaction will be approved or consummated.

The difficulties associated with any attempt to gain control of our company may discourage other potential bidders from emerging.

As of February 16, 2011, the Darden Investor Group beneficially owns shares representing approximately 30% of the outstanding shares of our common stock. The Darden Investor Group has substantial influence over the likelihood of consummating a change in control transaction for us.

Uncertainty regarding the future of our company may divert the attention of our management and employees and impact our relationships with counterparties.

The announcement that the Darden Investor Group is interested in exploring strategic alternatives for the Company may divert the attention of our management and employees from our day-to-day operations and impact our relationships with counterparties.

We could incur material costs and expense in connection with any proposal for a transaction.

Our board of directors has formed a Transaction Committee of independent directors to consider any transaction that may be proposed by the Darden Investor Group, as well as alternative transactions. The costs and expenses of the Transaction Committee, including the fees and expenses of the Transaction Committee's independent financial and legal advisors, will be payable by us whether or not any proposal is received or any transaction is consummated, and these costs and expense could be material. In addition, shortly after the announcement with respect to the Darden Investor Group, a number of law firms announced that they are investigating potential claims against us and our directors alleging breaches of fiduciary duties. If any such lawsuits are filed, we will incur additional costs and expenses.

Consummation of a transaction that results in substantially more debt to us could have an adverse effect on us, such as a downgrade of the ratings of our debt securities.

We can provide no assurance that the consummation of any particular transaction will not result in incurrence of substantial additional debt by us. Such additional debt could have significant adverse effects on us, such as further restricting our flexibility, negatively affecting our liquidity and a downgrade in the ratings of our debt securities.

ITEM 1B. Unresolved Staff Comments

None.

ITEM 2. Properties

A detailed description of our significant properties and associated 2010 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 14 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
2010		
Fourth Quarter	$ 15.88	$ 12.12
Third Quarter	14.47	10.65
Second Quarter	15.45	10.53
First Quarter	16.59	12.82
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

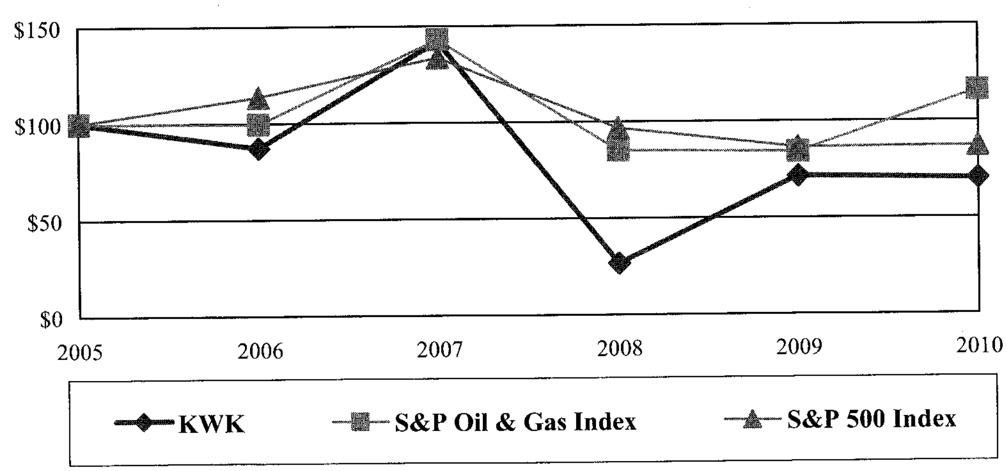
As of February 15, 2011, there were approximately 760 common stockholders of record.

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, 2005 to December 31, 2010, 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, 2010.

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 2010	3,088	$ 12.75	-	-
November 2010	1,323	$ 14.96	-	-
December 2010	-	-	-	-
Total	4,411	$ 13.41	-	-

(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,				
	2010 (2)	2009 (3)	2008 (4)	2007 (5)	2006
	(In thousands, except for per share data and ratios)				
Operating Results Information					
Total revenue	$ 928,331	$ 832,735	$ 800,641	$ 561,258	$ 390,362
Operating income (loss)	787,985	(613,873)	(249,697)	803,581	174,196
Income (loss) before income taxes	697,679	(836,856)	(585,077)	730,806	126,248
Net income (loss)	444,793	(545,239)	(373,622)	476,445	90,097
Net income (loss) attributable to Quicksilver	435,069	(557,473)	(378,276)	475,390	90,006
Diluted earnings (loss) per common share (1)	$ 2.45	$ (3.30)	$ (2.33)	$ 2.87	$ 0.58
Dividends paid per share	-	-	-	-	-
Financial Condition Information					
Property, plant and equipment - net	$ 3,067,845	$ 2,542,845	$ 3,298,830	$ 1,866,540	$ 1,546,823
Midstream assets held for sale - net	27,178	548,508	492,733	280,768	139,465
Total assets	3,512,334	3,612,882	4,498,208	2,773,751	1,881,052
Long-term debt	1,746,716	2,427,523	2,586,045	788,518	887,917
All other long-term obligations	243,110	121,877	282,101	434,190	191,627
Total equity	1,059,408	696,822	1,211,563	1,192,468	602,119
Cash Flow Information					
Cash provided by operating activities	$ 397,720	$ 612,240	$ 456,566	$ 319,104	$ 242,186
Purchases of property, plant and equipment	695,114	693,838	1,286,715	1,020,684	619,061

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

(2) Operating income for 2010 includes gains of $473.2 million and $57.6 million from the sales of KGS and BBEP Units, respectively. Operating income also includes charges for impairment of $28.6 million and $19.4 million for our HCDS and Canadian oil and gas properties, respectively.

(3) Operating loss for 2009 includes 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 income attributable to our proportionate ownership of BBEP and a charge of $102.1 million for impairment of that investment.

(4) Operating loss for 2008 includes a 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.

(5) Operating income and net income for 2007 include a gain of $628.7 million recognized from the divestiture of our Michigan, Indiana and Kentucky oil and gas properties and other assets and a charge of $63.5 million associated with a natural gas fixed-price sales contract that expired in March 2009 under which we no longer delivered natural gas produced from properties owned or operated by us.

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. Until the sale of all of our interests in KGS, we conducted 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
- 2010 Highlights – a summary of significant activities and events affecting Quicksilver
- *2011 Capital Program* – a summary of our planned capital expenditures during 2011
- *Financial Risk Management* – information about debt financing and financial risk management
- *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, development, exploitation and production of natural gas, NGLs, and oil. We focus primarily on unconventional reservoirs onshore in North America 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, development, exploitation and production activities to replace the reserves that we produce.

At December 31, 2010, 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 the Barnett Shale and Horseshoe Canyon. Our Barnett Shale Asset and Horseshoe Canyon Asset reserves made up 90% and 9%, respectively, of our proved reserves at December 31, 2010. Our acreage in the Horn River Basin provides us the most immediate additional opportunity for further application of this expertise.

We focus on three key value drivers:

- reserve growth;
- production growth; and
- maximizing our operating margin.

Our reserve growth relies on our ability to apply our technical and operational expertise to explore, develop and exploit unconventional reservoirs. We strive to increase reserves and production through aggressive management of our 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 reservoirs which align to our technical and operational expertise.

Acreage that we hold in our core operating areas is well suited for production increases through development and exploitation drilling. We perform workover and infrastructure projects to reduce ongoing operating costs and enhance 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 volume; cash flow from operating activities; and earnings per share.

	Years Ended December 31,		
	2010	2009	2008
Organic reserve growth [1]	19%	20%	29%
Production volume (Bcfe)	129.6	118.5	96.2
Cash flow from operating activities (in millions)	$ 397.7	$ 612.3	$ 456.6
Diluted earnings (loss) per share	$ 2.45	$ (3.30)	$ (2.33)

[1] This ratio is calculated by subtracting beginning of the year proved reserves from adjusted end of the year proved reserves and dividing by beginning of the year proved reserves. Adjusted end of the year reserves are calculated by adding back divested reserves and production and deducting acquired reserves from end of the year reserves.

2010 HIGHLIGHTS

Strategic Alternatives for Quicksilver

In October 2010, members of the Darden family ("the Darden Investor Group") sent a letter to our board of directors in which they expressed an interest in pursuing strategic alternatives for Quicksilver, including potentially taking us private. In response, our board of directors has formed a committee of independent directors to consider any transaction that may be proposed by the Darden Investor Group, as well as alternative transactions. The transaction committee retained independent legal and financial advisors. On February 2, 2011, the Darden Investor Group publicly indicated that it had confidence in the executability of a transaction that valued our common stock at a price in excess of $16 per share and would be interested in submitting a proposal subject to certain conditions described in its February 1, 2011 letter to our Board of Directors. On February 23, 2011, we amended our Amended and Restated Rights Agreement in connection with a request from the Darden Investor Group. The amendment permits the Darden Investor Group to engage in discussions with a potential co-investor regarding a possible acquisition of the Company. We are presently unable to assess the most likely outcome from this process or its impact on our stock price, financial position or results of operations.

Crestwood Transaction, Hill County Dry System and Midstream Operations

We completed the sale of all our interests in our publicly traded midstream partnership to Crestwood in October 2010. The Crestwood Transaction included our conveying:

- a 100% ownership interest in Quicksilver Gas Services Holdings LLC, which owned:
  - 5,696,752 common units of KGS;
  - 11,513,625 subordinated units of KGS representing limited partner interests in KGS;
  - 100% of the outstanding membership interests in Quicksilver Gas Services GP LLC including 469,944 general partner units in KGS and 100% of the outstanding incentive distribution rights in KGS; and,
- a subordinated promissory note issued to us by KGS with a carrying value of $58 million at September 30, 2010.

We received $700 million from Crestwood including $8 million in November from KGS for third-quarter distributions and transaction costs that we paid. We recognized a gain of $473 million. We have the right to receive up to an additional $72 million in future earn-out payments in 2012 and 2013, although no amounts attributable to the earn-out payments have been recognized through December 31, 2010.

Under the agreements governing the Crestwood Transaction, both parties agreed for two years not to solicit employees of the other party and we agreed not to compete with KGS with respect to the gathering, treating and processing of natural gas and the transportation of natural gas liquids in Denton, Hood, Somervell, Johnson, Tarrant, Parker, Bosque and Erath counties within the Barnett Shale. Thomas F. Darden continues as a director to KGS' general partner's board of directors, where he may serve until the later of October 1, 2012 or such time as we generate less than 50% of KGS' consolidated revenue in any fiscal year.

In connection with the closing of the Crestwood Transaction, we are providing transitional services to KGS through March 31, 2011 on customary terms. KGS and we also entered into an agreement for the joint development of areas governed by certain of our existing commercial agreements and further, we amended our existing commercial agreements. The most significant amendments include extending the terms of all gathering agreements with KGS through 2020 and establishing a fixed gathering rate of $0.55 per Mcf in the gathering system in the Alliance Leasehold.

In September 2010, our board of directors approved a plan for disposal of our HCDS, which gathers natural gas and delivers it to unaffiliated pipelines for further transport and sale downstream. As a result of the decision, we conducted an impairment analysis of the HCDS and recognized impairment expense of $28.6 million.

We have continued to report our interests sold in the Crestwood Transaction and the HCDS as part of our continuing operating results because our use of their midstream services subsequent to the closing of the Crestwood Transaction constitutes a "continuation of service" that precludes presentation of those businesses as discontinued operations under GAAP. The assets and liabilities of these operations have been reclassified and are segregated in our consolidated balance sheets.

The following summarizes the significant items related to our midstream operations:

	Years Ended December 31,		
	2010	2009	2008
		(In thousands)	
Income (loss) before income taxes for:			
Midstream operations - KGS	$ 34,339	$ 42,844	$ 39,053
Midstream operations - HCDS	124	(644)	(573)
Midstream impairment expense	(28,611)	-	-
Transaction costs	(2,555)	-	-
Results of midstream operations before income tax	3,297	42,200	38,480
Income tax expense	(1,265)	(15,428)	(12,836)
Results of midstream operations, net of income tax	$ 2,032	$ 26,772	$ 25,644

Lake Arlington Acquisition

In May 2010, we completed the acquisition of an additional 25% working interest in our company-operated Lake Arlington Project. We acquired the additional working interests for which we conveyed $62.1 million in cash and 3,619,901 of the BBEP Units that we owned. The acquired interests include proved natural gas reserves of 125 Bcf of which 82% were proved developed. As a result of our conveyance of 3.6 million BBEP Units for the acquired properties, we recognized a $35.4 million gain as other income in the second quarter of 2010.

BBEP Update

In April 2010, we finalized a global settlement agreement with BBEP and all other parties to our lawsuit whereby we received $18.0 million in cash. Pursuant to the agreement, we retained full voting rights for our units held in BBEP subject to the provisions of a limited standstill agreement and have named two directors to the board of directors of BBEP's general partner. BBEP also agreed to the reinstitution of the BBEP quarterly distributions and other governance accommodations. The $18.0 million settlement was recognized as other income in the second quarter of 2010. We also received quarterly distributions totaling $20.9 million in 2010. Completion of the acquisition of additional working interests in the Lake Arlington Project in May 2010 and the sale of 1.4 million BBEP Units in September 2010 reduced our ownership of to 31%. In October 2010, we sold an additional 650,000 BBEP Units and recognized a gain of $7.7 million. Subsequent to the October unit sale, our ownership of BBEP decreased to 29% as of December 31, 2010.

Horn River Basin Exploration

We brought two wells online in our Horn River Asset in the last half of 2009. In 2010, we spent $81.5 million for exploration and infrastructure development to bring our third and fourth wells online during the fourth quarter and to initiate construction on infrastructure to gather, compress and deliver gas to third-party processing facilities.

Increase in Production

Daily production increased 9% during 2010 from 2009. The production increase is discussed further in *Results of Operations* below.

2011 CAPITAL PROGRAM

We have budgeted our 2011 capital program to be spent in the following areas:

	Barnett Shale	Greater Green River Basin	Southern Alberta Basin	Other	Total U.S.	Horn River	Horseshoe Canyon	Other	Total Canada	Total Company
					(In millions, except wells)					
Drilling and completion	$ 234.2	$ 10.8	$ 0.3	$ -	$ 245.3	$ 26.9	$ 7.9	$ -	$ 34.8	$ 280.1
Midstream infrastructure	32.9	-	-	-	32.9	52.4	-	-	52.4	85.3
Leasehold acquisition	20.6	11.2	0.2	-	32.0	-	3.6	-	3.6	35.6
Corporate and other assets	1.0	0.2	0.1	32.1	33.4	11.1	0.1	9.9	21.1	54.5
Total budgeted capital	$ 288.7	$ 22.2	$ 0.6	$ 32.1	$ 343.6	$ 90.4	$ 11.6	$ 9.9	$ 111.9	$ 455.5
Wells drilled (net)	33	3	-	-	36	4	23	-	27	63
Wells completed (net)	76	3	-	-	79	1	23	-	24	103

For all of 2011, we expect our average production to be greater than our fourth quarter 2010 average production rate as we continue to develop our acreage in the Barnett Shale and conduct further exploration on our Horn River Asset, the Greater Green River Basin and the Southern Alberta Asset.

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.

RESULTS OF OPERATIONS

"Other U.S." refers to the combined amounts for our Greater Green River Asset and Southern Alberta Basin Asset.

Revenue

Natural Gas, NGL and Oil

Production Revenue:

	Natural Gas			NGL			Oil			Total		
	2010	2009	2008	2010	2009	2008	2010	2009	2008	2010	2009	2008
	(In millions)											
Barnett Shale	$ 321.2	$ 236.6	$ 371.1	$ 160.6	$ 135.5	$ 198.1	$ 11.8	$ 14.0	$ 30.4	$ 493.6	$ 386.1	$ 599.6
Other U.S.	2.3	0.5	0.8	0.5	0.3	0.8	10.0	8.0	14.8	12.8	8.8	16.4
Hedging	250.2	213.1	(2.4)	(24.1)	-	(8.6)	-	-	(7.1)	226.1	213.1	(18.1)
Total U.S.	573.7	450.2	369.5	137.0	135.8	190.3	21.8	22.0	38.1	732.5	608.0	597.9
Horseshoe Canyon	90.4	88.0	182.7	0.2	0.1	0.4	-	0.1	-	90.6	88.2	183.1
Horn River	10.6	2.5	-	-	-	-	-	-	-	10.6	2.5	-
Hedging	22.7	98.0	(0.2)	-	-	-	-	-	-	22.7	98.0	(0.2)
Total Canada	123.7	188.5	182.5	0.2	0.1	0.4	-	0.1	-	123.9	188.7	182.9
Total	$ 697.4	$ 638.7	$ 552.0	$ 137.2	$ 135.9	$ 190.7	$ 21.8	$ 22.1	$ 38.1	$ 856.4	$ 796.7	$ 780.8

Average Daily Production Volume:

	Natural Gas			NGL			Oil			Equivalent Total		
	2010	2009	2008	2010	2009	2008	2010	2009	2008	2010	2009	2008
	(MMcfd)			(Bbld)			(Bbld)			(MMcfed)		
Barnett Shale	207.9	168.3	122.8	11,913	13,598	11,425	433	729	873	281.9	254.2	196.6
Other U.S.	1.5	0.6	0.3	25	34	36	397	434	447	4.0	3.4	3.2
Total U.S.	209.4	168.9	123.1	11,938	13,632	11,461	830	1,163	1,320	285.9	257.6	199.8
Horseshoe Canyon	61.2	64.9	63.0	8	5	3	-	2	-	61.2	64.9	63.0
Horn River	8.0	2.0	-	-	-	-	-	-	-	8.0	2.0	-
Total Canada	69.2	66.9	63.0	8	5	3	-	2	-	69.2	66.9	63.0
Total	278.6	235.8	186.1	11,946	13,637	11,464	830	1,165	1,320	355.1	324.5	262.8

Average Realized Price:

	Natural Gas			NGL			Oil			Equivalent Total		
	2010	2009	2008	2010	2009	2008	2010	2009	2008	2010	2009	2008
	(per Mcf)			(per Bbl)			(per Bbl)			(per Mcfe)		
Barnett Shale	$ 4.23	$ 3.85	$ 8.26	$ 36.93	$ 27.31	$ 47.38	$ 74.71	$ 52.62	$ 95.16	$ 4.80	$ 4.16	$ 8.33
Other U.S.	4.16	3.62	7.43	56.04	27.02	70.52	68.77	50.53	89.41	8.68	7.41	13.92
Hedging	3.28	3.45	(0.05)	(5.53)	-	(2.06)	-	-	(14.72)	2.17	2.26	(0.25)
Total U.S.	$ 7.51	$ 7.31	$ 8.20	$ 31.44	$ 27.30	$ 45.39	$ 71.87	$ 51.84	$ 78.83	$ 7.02	$ 6.47	$ 8.18
Horseshoe Canyon	$ 5.06	$ 3.71	$ 7.92	$ 66.03	$ 54.66	$325.52	$ -	$ 54.80	$ -	$ 5.07	$ 3.71	$ 7.94
Horn River	3.64	3.43	-	-	-	-	-	-	-	3.64	3.43	-
Hedging	0.90	4.01	(0.01)	-	-	-	-	-	-	0.90	4.01	(0.01)
Total Canada	$ 4.90	$ 7.72	$ 7.91	$ 66.03	$ 54.66	$325.52	$ -	$ 54.80	$ -	$ 4.90	$ 7.72	$ 7.93
Total	$ 6.86	$ 7.42	$ 8.10	$ 31.46	$ 27.32	$ 45.44	$ 71.90	$ 51.85	$ 78.83	$ 6.61	$ 6.73	$ 8.12

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

	Natural Gas	NGL	Oil	Total
	(In thousands)			
Revenue for 2008	$ 552,046	$ 190,666	$ 38,076	$ 780,788
Volume variances	145,832	37,093	(5,394)	177,531
Hedge settlement variances	313,493	8,648	7,117	329,258
Price variances	(372,666)	(100,467)	(17,746)	(490,879)
Revenue for 2009	$ 638,705	$ 135,940	$ 22,053	$ 796,698
Volume variances	59,534	(16,840)	(6,352)	36,342
Hedge settlement variances	(37,904)	(24,113)	-	(62,017)
Price variances	37,078	42,174	6,074	85,326
Revenue for 2010	$ 697,413	$ 137,161	$ 21,775	$ 856,349

Natural gas revenue for 2010 increased from 2009 as a result of increases in production. The increase in natural gas volume from our Barnett Shale Asset was primarily the result of wells brought online during 2010. Canadian natural gas production increased as production from our Horn River Asset increased 6.0 MMcfd to 8.0 MMcfd for 2010. A 6% decrease in production from our Horseshoe Canyon Asset due to decreased capital spending was partially offset by increased production from our Horn River Asset. Higher market prices for natural gas in 2010 increased revenue, but the increase was offset by a decrease from hedge settlements.

The increase in NGL revenue for 2010 was due to increased market prices partially offset by payments made to settle hedges in 2010 and a 12% decrease in production from our Barnett Shale Asset compared to 2009. NGL production decreased primarily because we have focused our capital spending in areas of the Barnett Shale where dry natural gas is prevalent.

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, but this reduction was largely offset by a $313.5 million increase from hedge settlements. The increase in U.S. natural gas volume is due to wells brought online principally in our Barnett Shale Asset during 2009. These increases were partially offset by lower volume resulting from the Eni Transaction in June and natural production declines from existing wells in our Barnett Shale Asset. Canadian natural gas production increased due in part to wells placed into service during the third and fourth quarters of 2009 in our Horn River Asset.

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. Production in our Barnett Shale Asset increased 19% due to wells brought online 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.

Sales of Purchased Natural Gas and Costs of Purchased Natural Gas

	Years Ended December 31,		
	2010	2009	2008
		(In thousands)	
Sales of purchased natural gas:			
Purchases from Eni	$ 53,340	$ 11,195	$ -
Purchases from others	10,749	12,459	-
Total	64,089	23,654	-
Costs of purchased natural gas sold:			
Purchases from Eni	61,121	12,268	-
Purchases from others	10,825	11,265	-
Unrealized valuation (gain) loss on Gas Purchase Commitment	(6,625)	6,625	-
Total	65,321	30,158	-
Net sales and purchases of natural gas	$ (1,232)	$ (6,504)	$ -

Our purchase and sale of Eni's natural gas production for 2010 reflected a full year's activity as compared to six months' activity in 2009. Additionally, production has increased in our Alliance Leasehold, where Eni's working interests are located, because of new wells brought online throughout 2010. The Gas Purchase Commitment, which expired on December 31, 2010, is more fully described in Note 3 to the consolidated financial statements in Item 8 of this Annual Report.

Other Revenue

	Years Ended December 31,		
	2010	2009	2008
		(In thousands)	
Midstream revenue:			
KGS	$ 6,512	$ 7,153	$ 12,521
Canada	2,373	2,678	2,247
Other U.S.	1,352	2,683	2,613
Total midstream revenue	10,237	12,514	17,381
Gain (loss) from hedge ineffectiveness	(2,629)	(131)	1,621
Other	285	-	851
Total	$ 7,893	$ 12,383	$ 19,853

Other revenue, consisting primarily of revenue from the processing, gathering and marketing of natural gas and gains and losses attributable to hedge derivative ineffectiveness, decreased $4.5 million as compared to 2009. Midstream revenue was $2.3 million lower for 2010 primarily as a result of the sale of our interests in KGS in October 2010, a reduction of marketing revenue and lower volume on our HCDS. Losses attributable to ineffectiveness of our production hedge derivatives were greater for 2010 as compared to 2009.

We expect that midstream revenue will decrease in 2011 from 2010 levels due to the sale of significant midstream operations in the Crestwood Transaction.

Other revenue for 2009 was $7.5 million lower when compared to 2008. KGS' third-party revenue for 2009 was $5.4 million less compared to 2008. Additionally, 2008 gains attributable to ineffectiveness of derivatives hedging our production were reduced to a small loss for 2009.

Operating Expense

Lease Operating Expense

	Years Ended December 31,					
	2010		2009		2008	
	(In thousands, except per unit amounts)					
		Per Mcfe		Per Mcfe		Per Mcfe
Barnett Shale						
Cash expense	$ 47,231	$ 0.46	$ 41,538	$ 0.45	$ 53,136	$ 0.73
Equity compensation	841	0.01	761	0.01	1,130	0.02
	$ 48,072	$ 0.47	$ 42,299	$ 0.46	$ 54,266	$ 0.75
Other U.S.						
Cash expense	$ 5,945	$ 4.05	$ 6,348	$ 5.20	$ 6,275	$ 5.31
Equity compensation	182	0.12	195	0.16	190	0.16
	$ 6,127	$ 4.17	$ 6,543	$ 5.36	$ 6,465	$ 5.47
Total U.S.						
Cash expense	$ 53,176	$ 0.51	$ 47,886	$ 0.51	$ 59,411	$ 0.81
Equity compensation	1,023	0.01	956	0.01	1,320	0.02
	$ 54,199	$ 0.52	$ 48,842	$ 0.52	$ 60,731	$ 0.83
Horseshoe Canyon						
Cash expense	$ 27,221	$ 1.21	$ 27,881	$ 1.18	$ 28,350	$ 1.23
Equity compensation	1,271	0.06	2,114	0.09	2,146	0.09
	$ 28,492	$ 1.27	$ 29,995	$ 1.27	$ 30,496	$ 1.32
Horn River						
Cash expense	$ 2,145	$ 0.74	$ 190	$ 0.26	$ -	$ -
Equity compensation	-	-	-	-	-	-
	$ 2,145	$ 0.74	$ 190	$ 0.26	$ -	$ -
Total Canada						
Cash expense	$ 29,366	$ 1.16	$ 28,071	$ 1.15	$ 28,350	$ 1.23
Equity compensation	1,271	0.05	2,114	0.09	2,146	0.09
	$ 30,637	$ 1.21	$ 30,185	$ 1.24	$ 30,496	$ 1.32
Total Company						
Cash expense	$ 82,542	$ 0.63	$ 75,957	$ 0.64	$ 87,761	$ 0.91
Equity compensation	2,294	0.02	3,070	0.03	3,466	0.04
	$ 84,836	$ 0.65	$ 79,027	$ 0.67	$ 91,227	$ 0.95

Although U.S. lease operating expense for 2010 was 11% higher than 2009, lease operating expense per Mcfe was unchanged from 2009 to 2010. Increased expense was the result of an 11% increase in production volume in our Barnett Shale Asset for 2010 as compared to 2009.

Lease operating expense for 2010 in Canada was almost unchanged from 2009 despite a 3% increase in 2010 production compared to 2009. Lease operating expense for 2010 on a Canadian dollar basis increased C$1.7 million, or 4%, from 2009. Canadian lease operating expense on a Canadian dollar basis per Mcfe for 2010 increased less than 1% from 2009.

For all of 2011, we expect our lease operating expense to be less than our 2010 fourth-quarter rate per Mcfe due to a higher concentration of our production in our Barnett Shale Asset, which features lower lease operating costs on a per Mcfe basis.

U.S. lease operating expense was lower for 2009 despite a 29% production increase from 2008, primarily due to cost containment efforts in our Barnett Shale Asset during 2009. Lease operating expense per Mcfe in our Barnett Shale Asset 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 lease operating expense for 2009 was unchanged from 2008. Canadian lease operating expense per Mcfe for 2009 decreased because of production increases. Lease operating expense on a Canadian dollar basis for 2009 compared to 2008 increased C$3.3 million or 9% due primarily to the Canadian production increase.

Gathering, Processing and Transportation Expense

	Years Ended December 31,					
	2010		2009		2008	
	(In thousands, except per unit amounts)					
		Per Mcfe		Per Mcfe		Per Mcfe
Barnett Shale	$ 82,976	$ 0.81	$ 42,678	$ 0.46	$ 37,601	$ 0.52
Other U.S.	22	0.01	11	0.01	43	0.04
Total U.S.	$ 82,998	$ 0.80	$ 42,689	$ 0.45	$ 37,644	$ 0.51
Horseshoe Canyon	4,867	0.22	4,803	0.20	5,431	0.24
Horn River	6,143	2.11	1,196	1.62	-	-
Total Canada	11,010	0.44	5,999	0.25	5,431	0.24
Total	$ 94,008	$ 0.73	$ 48,688	$ 0.41	$ 43,075	$ 0.45

GPT for 2010 compared to 2009 increased primarily due to the loss of fees earned by KGS for gathering and processing production from our Barnett Shale Asset following the closing of the Crestwood Transaction. KGS' revenue earned from gathering and processing production from our Barnett Shale Asset, net of associated operating expense, averaged $18.5 million per quarter for the first three quarters of 2010. Fourth quarter 2010 GPT consisted primarily of fees charged by KGS. Canadian GPT increased for 2010 both in total dollars and on a per Mcfe basis primarily as a result of transportation fees associated with higher production from our Horn River Asset for 2010.

For all of 2011, we expect GPT to increase from the fourth quarter 2010 per Mcfe rate due to anticipated production increases in higher GPT cost areas and the sale of midstream operations in the Crestwood Transaction.

U.S. GPT for 2009 were 13% higher than 2008 although 2009 U.S. production increased 29% from 2008. On a per Mcfe basis, GPT decreased 11% as a result of an increase in the production of dry gas from our Lake Arlington Project and our Alliance Leasehold in 2009 as compared to 2008.

Production and Ad Valorem Taxes

	Years Ended December 31,					
	2010		2009		2008	
	(In thousands, except per unit amounts)					
		Per Mcfe		Per Mcfe		Per Mcfe
Production taxes						
U.S.	$ 9,171	$ 0.09	$ 4,746	$ 0.05	$ 8,549	$ 0.12
Canada	609	0.03	222	0.01	1,387	0.06
Total production taxes	9,780	0.07	4,968	0.04	9,936	0.10
Ad valorem taxes						
U.S.	$ 21,797	0.21	$ 16,658	0.18	$ 7,450	0.10
Canada	2,579	0.10	2,255	0.09	1,348	0.06
Total ad valorem taxes	24,376	0.19	18,913	0.16	8,798	0.09
Total	$ 34,156	$ 0.26	$ 23,881	$ 0.20	$ 18,734	$ 0.19

Production taxes for 2010 reflect a 15% increase in realized prices before hedge settlements for production from our Barnett Shale Asset and an 11% increase in production volume from our Barnett Shale Asset when compared to 2009. Higher U.S. ad valorem taxes for 2010 reflect the addition of wells, particularly in areas with higher ad valorem tax rates, and increases to ad valorem tax rates assessed by taxing entities in Texas when compared to 2009.

U.S. production taxes for 2009 decreased by 44% from 2008 because of the 50% decrease in realized prices before hedge settlements in our Barnett Shale Asset partially offset by increased production. U.S. ad valorem taxes for 2009 reflect the addition of wells and midstream facilities in our Barnett Shale Asset during 2009 as compared to 2008.

Depletion, Depreciation and Accretion

	Years Ended December 31,					
	2010		2009		2008	
	(In thousands, except per unit amounts)					
		Per Mcfe		Per Mcfe		Per Mcfe
Depletion						
U.S.	$ 125,243	$ 1.20	$ 127,888	$ 1.36	$ 120,845	$ 1.65
Canada	38,825	1.54	33,782	1.38	40,337	1.75
Total depletion	164,068	1.27	161,670	1.36	161,182	1.68
Depreciation of other fixed assets:						
U.S.	$ 30,252	$ 0.29	$ 33,329	$ 0.35	$ 21,751	$ 0.30
Canada	4,698	0.19	3,952	0.16	3,780	0.16
Total depreciation	34,950	0.27	37,281	0.31	25,531	0.27
Accretion	3,585	0.03	2,436	0.02	1,483	0.01
Total	$ 202,603	$ 1.56	$ 201,387	$ 1.70	$ 188,196	$ 1.96

U.S. depletion expense for 2010 was less than 2009 as a 12% decrease in the U.S. depletion rate was partially offset by an 11% increase in U.S. production. Changes in the U.S.-Canadian dollar exchange rate accounted for $3.7 million of the increase in Canadian depletion expense. To a lesser extent, increased Canadian production also contributed to the 15% increase in Canadian depletion expense. Both our U.S. and Canadian depletion rates have been impacted by the impairment charges recognized during 2009. The

Canadian depletion rate has been further impacted by evaluated Horn River Basin capital costs and future development costs included in proved reserve estimates at December 31, 2010.

The decrease in 2010 U.S. depreciation expense as compared to 2009 is the result of the sale of KGS. KGS' depreciation expense through September 2010 was $15.9 million as compared to $18.8 million for all of 2009.

Depletion expense 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 volume. 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 per Mcfe. We expect that our consolidated depletion rate for 2011 will be comparable to that of the 2010 fourth quarter.

The change in the exchange rate decreased Canadian 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 the addition of gathering and processing facilities in our Barnett Shale Asset.

Impairment Expense

As required under GAAP, we perform quarterly ceiling tests to assess impairment of our oil and gas properties. We also assess our fixed assets reported outside the full-cost pool when circumstances indicate impairment may have occurred. Information detailing the calculation of any impairment is more fully described in our "Critical Accounting Policies" found below and in Note 8 to the consolidated financial statements in Item 8 of this Annual Report.

In 2010, we recognized impairment expense of $48.0 million. As a result of the decision by our board of directors to approve a plan for disposal of our HCDS, we conducted an impairment analysis of the HCDS and recognized a $28.6 million non-cash charge for impairment. We also recognized a non-cash $19.4 million charge for impairment of our Canadian oil and gas properties. Our Canadian full-cost pool has undergone significant change associated with the cost of bringing our initial Horn River Asset wells online and associated field costs while the proved reserves recognized have been limited due to the lack of any substantial production history for the area.

We recognized non-cash charges totaling $979.6 million 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 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 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 $38.8 million. 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.

We recognized a non-cash charge of $633.5 million for impairment related to our U.S. oil and gas properties in December 2008. The impairment charge was primarily a result of significantly lower natural gas and NGL prices at year-end 2008 when compared to year-end 2007. Additionally, we determined that exploration costs incurred for evaluation of the Delaware Basin of West Texas would become part of the U.S. full-cost pool and no longer be excluded from depletion. As part of the evaluation of our activities in the Delaware Basin, we conducted an analysis of our midstream assets in West Texas for impairment. We recorded an impairment charge of $9.2 million to reduce the midstream assets to their estimated fair values.

General and Administrative Expense

	Years Ended December 31,					
	2010		2009		2008	
	(In thousands, except per unit amounts)					
		Per Mcfe		Per Mcfe		Per Mcfe
Cash expense	$ 55,313	$ 0.43	$ 55,200	$ 0.47	$ 49,982	$ 0.52
Litigation settlement	2,650	0.02	5,000	0.04	9,633	0.10
Equity compensation	22,144	0.17	17,043	0.14	12,639	0.13
Total	$ 80,107	$ 0.62	$ 77,243	$ 0.65	$ 72,254	$ 0.75

General and administrative expense for 2010 was $2.9 million greater than 2009 due to an increase in stock-based compensation expense, which included $3.6 million for the vesting of all of KGS' unvested stock-based compensation at the time of its sale. Legal and professional fees for 2010, however, were $5.9 million lower than in 2009 primarily due to settlement of our litigation with BBEP in April 2010 and a decrease in litigation settlement costs. These decreases were partially offset by $2.5 million incurred in 2010 for transaction costs, principally investment banking and legal fees, related to the Crestwood Transaction.

For all of 2011, we expect general and administrative expense per Mcfe to be less than the 2010 full year rate due to the absence of expense attributable to KGS prior to the Crestwood Transaction.

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.

Gain on Sale of KGS

In October 2010, we recognized a $473.2 million gain upon closing of the Crestwood Transaction. Further information regarding the transaction can be found in Note 3 to our consolidated financial statements included in Item 8 of this Annual Report.

Income from Earnings of BBEP

We record our portion of BBEP's earnings during the quarter in which their financial statements become publicly available. As a result, our 2010 and 2009 annual results of operations include BBEP's earnings for the 12 months ended September 30, 2010 and 2009, respectively. Our 2008 results of operations reflect BBEP's earnings from November 1, 2007, when we acquired BBEP Units, through September 30, 2008.

We recognized income of $22.3 million for equity earnings from our investment in BBEP based upon its reported earnings for the 12-month period ended September 30, 2010 as compared to income of $75.4 million recognized in 2009. BBEP continues to experience significant volatility in its net earnings primarily due to changes in the value of its derivative instruments for which it does not employ hedge accounting. Additionally, we reduced our ownership of BBEP Units in 2010. As of December 31, 2010, we owned BBEP Units representing 29% of total BBEP Units outstanding.

During 2009, we recognized $75.4 million for equity earnings from our investment in BBEP. The increase in equity earnings recognized during 2009 compared with 2008 is primarily due to mark-to-market accounting rendered by BBEP on its derivative portfolio.

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 the BBEP 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 and 2010, which resulted in no further impairment. Note 7 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 charge of $320.4 million to reduce the carrying value of our investment in BBEP to its fair value.

Other Income

In 2010, we settled our litigation against BBEP and received $18.0 million. We also recognized a gain of $35.4 million from the conveyance of 3.6 million BBEP common units as consideration in the acquisition of additional working interests in our Lake Arlington Project in May 2010. Gains totaling $22.2 million were recognized in September and October from the sale of 2.05 million BBEP common units. Note 3 to the consolidated financial statements found in this Annual Report contains additional information about these transactions.

Interest Expense

	Years Ended December 31,		
	2010	**2009**	**2008**
		(In thousands)	
Interest costs on debt outstanding	$ 175,877	$ 155,696	$ 105,108
Add:			
Non-cash interest [(1)]	17,226	18,410	13,215
Non-cash loss on early debt extinguishment	-	27,122	-
Less: Interest capitalized	(4,750)	(6,127)	(9,225)
Interest expense	$ 188,353	$ 195,101	$ 109,098

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

Interest costs on debt outstanding for 2010 were higher than 2009 primarily because of the full year impact of the Senior Notes Due 2016 and Senior Notes Due 2019 being outstanding. Overall interest expense was lower in 2010 than 2009 due to the absence of $27.1 million of expense related to the early retirement of a portion of our debt in 2009. We do not have a practice of maintaining higher debt balances throughout the quarter and minimizing them at quarter end for financial reporting purposes.

For all of 2011, we expect interest expense to be less than the 2010 full year amount due to interest expense attributable to KGS prior to the Crestwood Transaction.

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.

Income Taxes

	Years Ended December 31,		
	2010	2009	2008
		(In thousands)	
Income tax expense (benefit)	$ 252,886	$ (291,617)	$ (211,455)
Effective tax rate	36.2%	34.9%	36.1%

Our 2010 income tax provision increased from 2009 due primarily to higher income before taxes including the gain recognized on the sale of KGS and gains recognized from the disposition or sale of a portion of our BBEP Units. Also, the impact of permanent items for non-deductible expense impact the income tax rate applied to pre-tax income in 2010 and pre-tax loss in 2009. Additionally, we recognized an assessment of $1.0 million in Canada related to a predecessor's activities in 1997. The increase in our 2010 effective tax rate from the 2009 effective tax rate was primarily the result of U.S. and state income tax rates applied to the gains recognized from our sale of KGS and disposition of BBEP Units. For 2010, our effective rate in the U.S. was 35.8% and in Canada, excluding the $1.0 million assessment, it was 40.2%. Our U.S. operations generated more than 99% of our pre-tax income.

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 losses in both the U.S. and Canada that were taxed at 35.0% and 26.2%, respectively.

Quicksilver Resources Inc. and its Restricted Subsidiaries

Information about Quicksilver and our restricted and unrestricted subsidiaries is included in Note 18 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 which prior to October 1, 2010 consisted of KGS and its subsidiaries. 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,		
	2010	2009	2008
		(In thousands)	
Net cash provided by operating activities	$ 397,720	$ 612,303	$ 456,566

Net cash provided by operations for 2010 decreased from 2009, primarily due to our lower realized prices (including hedging effects), an increase in income tax payments and an increase in cash payments for interest. These reductions of operating cash were partially offset by payment received for settlement of our BBEP litigation and an additional $9.8 million in BBEP distributions in 2010 as compared to 2009.

Cash flows provided by operating activities in 2009 increased from 2008 because of a net $93.9 million increase in production revenue, including commodity derivative settlements, and receipt of a $41.1 million U.S. federal income tax refund as compared to income tax payments of $49.4 million in 2008. Other components of cash flows provided by operations for 2009 decreased $40.3 million for additional interest payments on our outstanding debt, net of interest rate derivative settlements, and increased losses from third-party natural gas purchase and sale activity of $15.8 million as compared to 2008. 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. The remaining increase in 2009 operating cash flows was a result of lower operating and general and administrative expense and the timing of cash receipts and disbursements that affected working capital.

Investing Cash Flows

	Years Ended December 31,		
	2010	**2009**	**2008**
		(In thousands)	
Purchases of property, plant and equipment	$ (695,114)	$ (693,838)	$ (1,286,715)
Alliance Acquisition	-	-	(993,212)
Proceeds from sale of KGS LP	699,973	-	-
Proceeds from sale of BBEP units	34,016	-	-
Proceeds from sales of properties & equipment	9,953	220,974	1,339
Net cash provided (used) by investing activities	$ 48,828	$ (472,864)	$ (2,278,588)

For each of the three years ended December 31, 2010, we have spent significant cash resources for the development of our large acreage positions in our core areas in the Barnett Shale and Horseshoe Canyon. In addition, our expenditures for gas processing and gathering assets grew significantly from the growth of KGS. We completed several significant transactions during the three years ended December 31, 2010, including the Crestwood Transaction in 2010 with net cash proceeds of $700 million after transaction costs, the 2009 Eni Transaction with net cash proceeds of $219.2 million and our 2008 Alliance Acquisition for cash of $1.0 billion.

Our purchases of property, plant and equipment in 2010 continued to reflect our decision to reduce our exploration and development activity in response to low natural gas and NGL prices. Exploration and development costs incurred were $649.5 million in 2010. Total costs incurred in 2010 of $734.8 million, included $54.4 million of BBEP Units conveyed in the Lake Arlington Project acquisition. Costs incurred for facilities and other equipment were $85.3 million, which includes more than $30 million for Horn River Basin facilities. Another $45.0 million of our remaining expenditures were related primarily to expansion of midstream facilities owned by KGS.

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 gathering and processing operations. We drilled 154 (93.2 net) wells in the Barnett Shale and 141 (36.1 net) wells in Horseshoe Canyon. Our 2009 midstream capital investment of $123.0 million was primarily related to expansion of our gas processing and gathering facilities in our Barnett Shale Asset.

In 2008, we purchased 101 wells, 93 producing wells and 8 unfinished wells, in the Alliance Acquisition and drilled 296 (259.7 net) wells in the Barnett Shale and 373 (156.9 net) wells in Horseshoe Canyon. Additionally, the assets purchased in the Alliance Acquisition included a gathering system and we invested $230.4 million and $4.3 million for gas gathering and processing facilities in the Barnett Shale and Horseshoe Canyon, respectively.

Financing Cash Flows

	Years Ended December 31,		
	2010	2009	2008
		(In thousands)	
Issuance of debt	$ 690,058	$ 1,420,727	$ 2,948,672
Repayments of debt	(1,031,736)	(1,649,630)	(1,096,163)
Debt issuance costs	(3,111)	(32,472)	(25,219)
Gas Purchase Commitment	-	58,294	-
Gas Purchase Commitment repayments	(44,119)	(14,175)	-
Issuance of KGS common units	11,054	80,729	-
Distributions paid on KGS common units	(13,550)	(9,925)	(8,644)
Proceeds from exercise of stock options	1,801	4,046	1,244
Taxes paid on vest of KGS equity compensation	(1,144)	(63)	-
Excess tax benefits on exercise of stock options	3,513	-	-
Purchase of treasury stock	(4,910)	(922)	(23,137)
Net cash provided (used) by financing activities	$ (392,144)	$ (143,391)	$ 1,796,753

Net financing cash flows in 2010 include $455 million used to repay all outstanding balances on our Senior Secured Credit Facility using a portion of the proceeds from the Crestwood Transaction. The completion of our obligation under the Gas Purchase Commitment during 2010 also contributed to the use of cash by financing activities.

Net financing cash flows 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 in 2009 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.

Liquidity and Borrowing Capacity

During the fourth quarter of 2010, our Senior Secured Credit Facility maturity was extended by one year and now matures on February 9, 2013. The Senior Secured Credit Facility availability is governed by a borrowing base and determined annually by the lenders taking into consideration the estimated value of oil and gas properties and any other relevant information, all in accordance with their customary practices for oil and gas loans in effect from time to time. At December 31, 2010, the borrowing base and commitments were $1.0 billion and the aggregate letter of credit capacity was $175 million. The Senior Secured Credit Facility provides us an option to increase availability by up to $250 million, with a maximum of $1.45 billion with lender consents and additional commitments. We can also extend the maturity date 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 lesser of the borrowing base or commitments. 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, substantially all of our oil and gas properties. We have also pledged a portion of our equity interests in BBEP to secure our obligations under the Senior Secured Credit Facility. At December 31, 2010, there was

$930 million available under the facility. Our ability to remain in compliance with the financial covenants in our credit facilities 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.

Additional information about our debt and related covenants are more fully described in Note 11 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 2011 capital expenditure program will be substantially funded by cash flow from operations, but expect that we will also utilize the Senior Secured Credit Facility.

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, 2010, as compared to our balance sheet as of December 31, 2009:

- Our net property, plant and equipment balance increased $525.0 million from December 31, 2009 to December 31, 2010. Our property, plant and equipment balances increased by $694.8 million because of costs incurred for property, plant and equipment and assets recognized when retirement obligations were established for new wells and facilities. Changes for U.S.-Canadian exchange rates further increased our property, plant and equipment balances $29.9 million. Offsetting the increases was DD&A and impairment expense of $199.7 million.
- Our current and non-current derivative assets and liabilities increased $34.8 million on a net basis. We received $194.0 million for settlement of commodity derivatives and $50.8 million for settlement of interest rate derivatives. The $279.3 million increase in the valuation of our open derivative positions at December 31, 2010 more than offset these decreases. Our current deferred income tax liability related to our derivatives decreased 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.
- Long-term debt was reduced by net repayments on the Senior Secured Credit Facility of $475.8 million using proceeds from the Crestwood Transaction. We have also classified the outstanding balance of our contingently convertible debentures as current as the holders of the debentures can require us to repay all or a portion of the debentures on November 1, 2011. These decreases were slightly offset by the deferral of gains from our settled interest rate swap derivatives for $30.8 million which will continue to be recognized as a reduction of interest expense over terms of the associated debt instruments.
- Our net deferred income tax position changed from a net asset position of $91.9 million to a net liability position of $157.0 million primarily because of deferred income tax expense recognized on the gains from sales of KGS and BBEP Units and 2010 income.
- Completion of the sale of KGS reduced net assets and net liabilities for our midstream business held for sale and noncontrolling equity. At December 31, 2010, net assets and net liabilities held for sale remain only for the HCDS.

Contractual Obligations and Commercial Commitments

Contractual Obligations. Information regarding our contractual and scheduled interest obligations, at December 31, 2010, 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	$ 1,896,114	$ 150,000	$ 21,114	$ 1,425,000	$ 300,000
Scheduled interest obligations	951,032	171,078	501,373	184,775	93,806
GPT contracts	414,304	44,315	187,321	109,488	73,180
Drilling rig contracts	55,978	31,827	24,151	-	-
Purchase obligations	1,136	1,136	-	-	-
Asset retirement obligations	57,809	1,574	756	504	54,975
Unrecognized tax benefits	9,219	-	9,219	-	-
Operating lease obligations	40,450	3,301	11,821	6,930	18,398
Total obligations	$ 3,426,042	$ 403,231	$ 755,755	$ 1,726,697	$ 540,359

- *Long-Term Debt.* As of December 31, 2010, our outstanding indebtedness included $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 (all before original issue discount) and outstanding amounts under our Senior Secured Credit Facility. Based upon our debt outstanding and interest rates as of December 31, 2010, we anticipate interest payments, including our scheduled interest obligations, to be $171.1 million in 2011. Should we be required to borrow on our Senior Secured Credit Facility and based on interest rates as of December 31, 2010, each $50 million in borrowings would result in additional annual interest payments of $0.9 million. If the current borrowing availability under our Senior Secured Credit Facility were to be fully utilized by year-end 2011 at interest rates as of December 31, 2010, we estimate that annual interest payments would increase by $31.5 million. If interest rates increase 1% on our December 31, 2010 variable debt balances of $21.1 million our annual pre-tax income would decrease or increase by $0.2 million.

- *Scheduled Interest Obligations.* As of December 31, 2010, 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, $2.8 million annually on our $150 million of contingently convertible debentures and $6.3 million annually on our Senior Secured Credit Facility.

- *Gathering, Processing and Transportation Contracts.* Under contracts with various third parties, we are obligated to provide minimum daily natural gas volume for gathering, processing, fractionation or transportation, as determined on a monthly basis, or pay for any volume deficiencies at a specified reservation fee rate. Our production is expected to exceed the daily volume 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 $20,000 to $26,500 for the entire lease term regardless of our utilization of the drilling rigs.

- *Purchase Obligations.* At December 31, 2010, we were under contract to purchase goods and services for use in field and gas plant operations.

- *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. At December 31, 2010, $8.9 million of the unrecognized tax benefits, 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, 2010:

	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	$ 39,366	$ 39,366	$ -	$ -	$ -
Standby letters of credit	49,237	49,237	-	-	-
Total	$ 88,603	$ 88,603	$ -	$ -	$ -

- *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 $28.9 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. During 2011 we expect our utilization of letters of credit to increase in support of transportation contracts in the Horn River Basin by up to $6.5 million.

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, expense 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. Under the current rule adopted by the SEC in December 2008, we incorporated the following changes into our proved reserve process and related disclosures for 2009 and 2010 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 costs at the time of the reserve estimate and are held constant into future periods. Our estimates of proved reserves are determined 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 2010 and 2009 are presented in compliance with this new rule. Our 2008 proved reserve estimates and related disclosures were prepared in compliance with the SEC rule then in effect.

The current SEC rule allows PUD reserves to be booked beyond one offset location where reliable technology exists that establishes reasonable certainty of economic producibility at greater distances, whereas the prior rule allowed recognizing only one offset. In accordance with the current rule, we recognized incremental PUD locations in our Barnett Shale Asset. In our Barnett Shale Asset, we had 360 proved undeveloped gas well locations at December 31, 2010, including 104 locations that are more than one offset. Additional information regarding our 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 over the last four years 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 acquisition, exploration, development and exploitation 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 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) adjusted to reflect local differentials and contract provisions, unescalated 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 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. The current SEC rule requires the use of the future net cash flows from proved reserves discounted at 10%. Therefore, the future net cash flows associated with the 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 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 time that we conduct a ceiling test, 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 is immediately recorded to earnings. The ineffective portion of the hedge relationship is recognized currently as a component of other revenue.

The fair values of natural gas and NGL derivatives are estimated using published market prices of natural gas and NGLs for the periods covered by the contracts. Estimates are determined by applying the net differential between the prices in each derivative and market prices for future periods, to the volume stipulated in each contract to arrive at an estimated value of future cash flow streams. These estimated future cash flow values are 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 and the changes in value of the hedged items are also 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 all interest rate derivatives is estimated using published LIBOR interest rates for the periods covered by the contracts. The estimates are 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, length of 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

Estimating the grant date fair value of our stock-based compensation requires management to make assumptions and to apply judgment to determine the grant date 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 carryforwards 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 materially affecting our consolidated financial statements 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, 2010, the following forecasted production has been hedged with price collars or price swaps.

Production Year	Daily Production Gas	Daily Production NGL
	MMcfd	MBbld
2011	190	8
2012	130	-
2013	70	-
2014-2015	30	-

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 greater by $248.9 million and $310.9 million for 2010 and 2009, respectively, and $18.4 million lower for 2008.

The following table details our open derivative positions at December 31, 2010:

Product	Type	Remaining Contract Period	Volume	Weighted Avg Price Per Mcf or Bbl	Fair Value Total	2011	2012	2013	2014	2015
					(In thousands)					
Gas	Collar	Jan 2011-Dec 2011	10 MMcfd	$ 6.00- 7.00	$ 5,508	$ 5,508	$ -	$ -	$ -	$ -
Gas	Collar	Jan 2011-Dec 2011	10 MMcfd	6.00- 7.00	5,508	5,508	-	-	-	-
Gas	Collar	Jan 2011-Dec 2011	20 MMcfd	6.00- 7.00	11,016	11,016	-	-	-	-
Gas	Collar	Jan 2011-Dec 2011	10 MMcfd	6.25- 7.50	6,377	6,377	-	-	-	-
Gas	Collar	Jan 2011-Dec 2011	10 MMcfd	6.25- 7.50	6,377	6,377	-	-	-	-
Gas	Collar	Jan 2011-Dec 2011	20 MMcfd	6.25- 7.50	12,755	12,755	-	-	-	-
Gas	Collar	Jan 2011-Dec 2012	20 MMcfd	6.50- 7.15	25,470	14,423	11,047	-	-	-
Gas	Collar	Jan 2011-Dec 2012	20 MMcfd	6.50- 7.18	25,577	14,484	11,093	-	-	-
Gas	Collar	Jan 2012-Dec 2012	20 MMcfd	6.50- 8.01	11,416	-	11,416	-	-	-
Gas	Basis	Jan 2011-Dec 2011	10 MMcfd	(1)	615	615	-	-	-	-
Gas	Basis	Jan 2011-Dec 2011	10 MMcfd	(1)	615	615	-	-	-	-
Gas	Basis	Jan 2011-Dec 2011	20 MMcfd	(1)	1,230	1,230	-	-	-	-
Gas	Swap	Jan 2011-Dec 2013	10 MMcfd	$ 5.00	151	1,973	(353)	(1,469)	-	-
Gas	Swap	Jan 2011-Dec 2013	10 MMcfd	5.00	151	1,973	(353)	(1,469)	-	-
Gas	Swap	Jan 2011-Dec 2013	10 MMcfd	5.00	151	1,973	(353)	(1,469)	-	-
Gas	Swap	Jan 2011-Dec 2013	10 MMcfd	5.00	151	1,973	(353)	(1,469)	-	-
Gas	Swap	Jan 2011-Dec 2015	10 MMcfd	6.00	13,743	5,083	3,246	2,349	1,788	1,277
Gas	Swap	Jan 2011-Dec 2015	20 MMcfd	6.00	27,486	10,166	6,492	4,698	3,576	2,554
NGL	Swap	Jan 2011-Dec 2011	3 MBbld	36.06	(5,302)	(5,302)	-	-	-	-
NGL	Swap	Jan 2011-Dec 2011	2 MBbld	36.31	(3,356)	(3,356)	-	-	-	-
NGL	Swap	Jan 2011-Dec 2011	3 MBbld	41.95	1,123	1,123	-	-	-	-
			Grand Total		$ 146,762	$ 94,514	$ 41,882	$ 1,171	$ 5,364	$ 3,831

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

The following table summarizes derivatives entered into since January 1, 2011:

Product	Type	Contract Period	Volume	Weighted Avg Price Per Mcf or Bbl
NGL	Swap	Jan 2011-Dec 2011	1.0 MBbld	$ 40.50
NGL	Swap	Jan 2011-Dec 2011	1.5 MBbld	40.42

Interest Rate Risk

In February 2010, we executed the early settlement of the 2009 interest rate swaps that were designated as fair value hedges of our senior notes due 2015 and our senior subordinated notes. We received cash of $18.0 million in the settlement, including $3.7 million for interest previously accrued and earned, and recognized the remaining $14.3 million as a fair value adjustment to our debt which will be amortized over the remaining period that the debt is outstanding.

In February 2010, we entered into new interest swaps to hedge the same debt instruments. We executed early settlement of a portion of the 2010 interest rate swaps in May 2010 and the remaining 2010 interest swaps in July 2010 for $6.8 million and $16.7 million, respectively. These settlements included $7.0 million for interest previously accrued and earned. The remaining cash of $16.5 million was recognized as a fair value adjustment to our debt, which will continue to be recognized as a reduction of interest expense over the life of the associated underlying debt instruments.

For 2010 and 2009, interest expense decreased $14.0 million and $13.7 million, respectively, because of our interest rate swaps.

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

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 2010, 2009 and 2008, non-functional currency transactions resulted in losses of $0.5 million, $2.2 million, and $3.3 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, 2010 and 2009, 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, 2010. 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 Quicksilver Resources Inc. and subsidiaries at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, 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, 2010, 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 11, 2011 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Fort Worth, Texas
March 11, 2011

QUICKSILVER RESOURCES INC.
CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)
FOR THE YEARS ENDED DECEMBER 31, 2010, 2009 AND 2008
In thousands, except for per share data

	2010	2009	2008
Revenue			
Natural gas, NGL and oil	$ 856,349	$ 796,698	$ 780,788
Sales of purchased natural gas	64,089	23,654	-
Other	7,893	12,383	19,853
Total revenue	928,331	832,735	800,641
Operating expense			
Lease operating expense	84,836	79,027	91,227
Gathering, processing and transportation expense	94,008	48,688	43,075
Production and ad valorem taxes	34,156	23,881	18,734
Costs of purchased natural gas	65,321	30,158	-
Other operating expense	4,522	6,684	3,337
Depletion, depreciation and accretion	202,603	201,387	188,196
Impairment expense	47,997	979,540	633,515
General and administrative expense	80,107	77,243	72,254
Total expense	613,550	1,446,608	1,050,338
Gain on sale of KGS	473,204	-	-
Operating income (loss)	787,985	(613,873)	(249,697)
Income from earnings of BBEP	22,323	75,444	93,298
Impairment of investment in BBEP	-	(102,084)	(320,387)
Other income (expense) - net	75,724	(1,242)	807
Interest expense	(188,353)	(195,101)	(109,098)
Income (loss) before income taxes	697,679	(836,856)	(585,077)
Income tax (expense) benefit	(252,886)	291,617	211,455
Net income (loss)	444,793	(545,239)	(373,622)
Net income attributable to noncontrolling interests	(9,724)	(12,234)	(4,654)
Net income (loss) attributable to Quicksilver	$ 435,069	$ (557,473)	$ (378,276)
Other comprehensive income (loss)			
Reclassification adjustments related to settlements of derivative contracts - net of income tax	(164,016)	(211,863)	11,969
Net change in derivative fair value - net of income tax	156,850	125,989	182,472
Foreign currency translation adjustment	16,017	22,106	(49,403)
Comprehensive income (loss)	$ 443,920	$ (621,241)	$ (233,238)
Earnings (loss) per common share - basic	$ 2.56	$ (3.30)	$ (2.33)
Earnings (loss) per common share - diluted	$ 2.45	$ (3.30)	$ (2.33)

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

QUICKSILVER RESOURCES INC.
CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2010 AND 2009
In thousands, except for share data

	2010	2009
ASSETS		
Current assets		
Cash and cash equivalents	$ 54,937	$ 1,037
Accounts receivable - net of allowance for doubtful accounts	63,380	63,738
Derivative assets at fair value	89,205	97,957
Other current assets	30,650	54,652
Total current assets	238,172	217,384
Investments in equity affiliates	83,341	112,763
Property, plant and equipment - net		
Oil and gas properties, full cost method (including unevaluated costs of $314,543 and $458,037, respectively)	2,844,919	2,338,244
Other property and equipment	222,926	204,601
Property, plant and equipment - net	3,067,845	2,542,845
Assets of midstream operations held for sale	27,178	548,508
Derivative assets at fair value	57,557	14,427
Deferred income taxes	-	133,051
Other assets	38,241	43,904
	$ 3,512,334	$ 3,612,882
LIABILITIES AND EQUITY		
Current liabilities		
Current portion of long-term debt	$ 143,478	$ -
Accounts payable	167,857	149,766
Accrued liabilities	122,904	153,598
Derivative liabilities at fair value	-	395
Current deferred tax liability	28,861	51,675
Total current liabilities	463,100	355,434
Long-term debt	1,746,716	2,302,123
Liabilities of midstream operations held for sale	1,431	148,191
Asset retirement obligations	56,235	48,472
Other liabilities	28,461	20,691
Deferred income taxes	156,983	41,149
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 shares authorized, and 175,524,816 and 174,469,836 shares issued, respectively	1,755	1,745
Paid in capital in excess of par value	714,869	730,265
Treasury stock of 5,050,450 and 4,704,448 shares, respectively	(41,487)	(36,363)
Accumulated other comprehensive income	130,187	121,336
Retained earnings (deficit)	254,084	(180,985)
Quicksilver stockholders' equity	1,059,408	635,998
Noncontrolling interests	-	60,824
Total equity	1,059,408	696,822
	$ 3,512,334	$ 3,612,882

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, 2010, 2009 AND 2008
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. 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 of 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 of 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
Net income	-	-	-	-	435,069	9,724	444,793
Hedge derivative contract settlements reclassified into earnings from accumulated other comprehensive income, net of income tax of $84,835	-	-	-	(164,016)	-	-	(164,016)
Net change in derivative fair value, net of income tax of $78,616	-	-	-	156,850	-	-	156,850
Foreign currency translation adjustment	-	-	-	16,017	-	-	16,017
Issuance & vesting of stock compensation	7	23,531	(5,124)	-	-	4,339	22,753
Stock option exercises	3	2,012	-	-	-	-	2,015
Issuance of KGS common units	-	6,746	-	-	-	4,308	11,054
Distributions paid on KGS common units	-	-	-	-	-	(13,550)	(13,550)
Disposition of KGS partnership interests	-	(47,685)	-	-	-	(65,645)	(113,330)
Balances at December 31. 2010	$ 1,755	$ 714,869	$ (41,487)	$ 130,187	$ 254,084	$ -	$ 1,059,408

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

QUICKSILVER RESOURCES INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS END DECEMBER 31, 2010, 2009 AND 2008
In thousands

	2010	2009	2008
Operating activities:			
Net income (loss)	$ 444,793	$ (545,239)	$ (373,622)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and accretion	202,603	201,387	188,196
Impairment expense	47,997	979,540	633,515
Deferred income tax expense (benefit)	179,715	(291,414)	(166,440)
Non-cash (gain) loss from hedging and derivative activities	(58,892)	6,756	(1,139)
Gain on sale of KGS	(473,204)	-	-
Divestiture expenses	2,555	-	-
Stock-based compensation	25,990	20,815	16,128
Non-cash interest expense	17,226	45,532	13,215
Gain on disposition of BBEP units	(57,584)	-	-
Income from BBEP in excess of cash distributions	(1,417)	(64,344)	(50,762)
Impairment of investment in BBEP	-	102,084	320,387
Other	(168)	747	605
Changes in assets and liabilities			
Accounts receivable	(9,501)	77,527	(53,071)
Derivative assets at fair value	30,816	54,896	-
Prepaid expenses and other assets	6,364	3,061	(5,448)
Accounts payable	33,957	(12,320)	7,602
Income taxes payable	4,611	60	(46,561)
Accrued and other liabilities	1,859	33,215	(26,039)
Net cash provided by operating activities	397,720	612,303	456,566
Investing activities:			
Purchases of property, plant and equipment	(695,114)	(693,838)	(1,286,715)
Alliance Acquisition	-	-	(993,212)
Proceeds from sale of KGS	699,973	-	-
Proceeds from sale of BBEP units	34,016	-	-
Proceeds from sale of properties and equipment	9,953	220,974	1,339
Net cash provided (used) by investing activities	48,828	(472,864)	(2,278,588)
Financing activities:			
Issuance of debt	690,058	1,420,727	2,948,672
Repayments of debt	(1,031,736)	(1,649,630)	(1,096,163)
Debt issuance costs paid	(3,111)	(32,472)	(25,219)
Gas Purchase Commitment assumed	-	58,294	-
Gas Purchase Commitment repayments	(44,119)	(14,175)	-
Issuance of KGS common units - net offering costs	11,054	80,729	-
Distributions paid on KGS common units	(13,550)	(9,925)	(8,644)
Proceeds from exercise of stock options	1,801	4,046	1,244
Excess tax benefits on exercise of stock options	3,513	-	-
Taxes paid on vesting of KGS equity compensation	(1,144)	(63)	-
Purchase of treasury stock	(4,910)	(922)	(23,137)
Net cash provided (used) by financing activities	(392,144)	(143,391)	1,796,753
Effect of exchange rate changes in cash	(1,252)	2,889	(109)
Net increase (decrease) in cash	53,152	(1,063)	(25,378)
Cash and cash equivalents at beginning of period	1,785	2,848	28,226
Cash and cash equivalents at end of period	$ 54,937	$ 1,785	$ 2,848

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

QUICKSILVER RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED DECEMBER 31, 2010, 2009 AND 2008

1. NATURE OF OPERATIONS

We are an independent oil and gas company incorporated in the state of Delaware and headquartered in Fort Worth, Texas. We engage in the acquisition, exploration, development, exploitation, production and sale of natural gas, NGLs and oil as well as the marketing, processing and transportation of natural gas in North America. As of December 31, 2010, our significant oil and gas reserves and operations are located in:

- Texas
- U.S. Rocky Mountains
- Alberta
- British Columbia

We have offices located in:

- Fort Worth, Texas
- Glen Rose, Texas
- Cut Bank, Montana
- Steamboat Springs, Colorado
- Calgary, Alberta
- Fort Nelson, British Columbia

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 our accounts and all of our 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.

Changes in Presentation

Certain reclassifications have been made to the 2009 and 2008 financial statements for presentations adopted in 2010.

Stock Split

In January 2008, our Board of Directors declared a two-for-one stock split of our outstanding common stock effected in the form of a stock dividend. The stock dividend was completed in January 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 expense 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 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 2010, two purchasers individually accounted for 17% and 12% of our consolidated natural gas, NGL and oil sales. During 2009, three purchasers individually accounted for 15%, 13% 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 is no longer probable, 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.

Investments in Equity Affiliates

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. Consequently, our 2010 and 2009 annual results of operations include BBEP's earnings for the 12 months ended September 30, 2010 and 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, 2010 that will affect BBEP's results of operations after that date. See Note 7 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, development and exploitation 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 8 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.

Inventory

Inventories were comprised of $25.3 million and $42.6 million of materials and parts and $2.1 million and $1.6 million of NGLs as of December 31, 2010 and 2009, respectively. Our materials, parts and supplies inventory is primarily comprised of oil and gas drilling or repair items such as tubing, casing, chemicals, operating supplies and ordinary maintenance materials and parts. The materials, parts and supplies inventory is primarily acquired for use in future drilling operations or repair operations and is carried at the lower of cost or market, on a first-in, first-out cost basis. "Market," in the context of inventory valuation, represents net realizable value, which is the amount that we are allowed to bill to the joint accounts under joint operating agreements to which we are a party. Valuation reserve allowances for materials and supplies inventories are recorded as reductions to the carrying values of the materials and supply inventories in our consolidated balance sheets and as lease operating expense in the accompanying consolidated statements of operations.

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, 2010 and 2009, 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 convertible debentures, which results in our recognizing 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. Our board of directors may elect to 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 exchange rate and statement of income items are translated at the weighted average exchange rate 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. Until we sold all of our interests in KGS in October 2010, we included the results of operations and financial position of KGS in our consolidated financial statements and recognized the portion of KGS' results of operations attributable to unaffiliated unitholders as a component of "income attributable to noncontrolling interests."

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 17.

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. No pronouncements materially affecting our financial statements have been issued since the filing of our 2009 Annual Report on Form 10-K.

3. ACQUISITIONS AND DIVESTITURES

2010 Crestwood Transaction and Midstream Operations

In October 2010, we completed the sale of all of our interests in KGS to Crestwood in October 2010. The Crestwood Transaction included our conveying:

- a 100% ownership interest in Quicksilver Gas Services Holdings LLC, which owned;
  - 5,696,752 common units of KGS;
  - 11,513,625 subordinated units of KGS representing limited partner interests in KGS;
  - 100% of the outstanding membership interests in Quicksilver Gas Services GP LLC including 469,944 general partner units in KGS and 100% of the outstanding incentive distribution rights in KGS; and,

- a subordinated promissory note issued to us by KGS with a carrying value of $58 million at September 30, 2010.

We received net proceeds of $700 million including $8.0 million from KGS for third quarter 2010 distributions and after transaction costs. We recognized a gain of $473.2 million. We have the right to collect up to an additional $72 million in future earn-out payments in 2012 and 2013, although we have recognized no assets related to these opportunities.

Under the agreements governing the Crestwood Transaction, both parties agreed for two years not to solicit employees of the other party and we agreed not to compete with KGS with respect to the gathering, treating and processing of natural gas and the transportation of natural gas liquids in Denton, Hood, Somervell, Johnson, Tarrant, Parker, Bosque and Erath counties in Texas. We appointed Thomas F. Darden to KGS' general partner's board of directors until the later of the second anniversary of the closing and such time as we generate less than 50% of their consolidated revenue in any fiscal year.

In connection with the closing of the Crestwood Transaction, we are providing transitional services to KGS through March 2011 on customary terms. KGS and we also entered into an agreement for the joint development of areas governed by certain of our existing commercial agreements and further, we amended our existing commercial agreements. The most significant amendments include extending the terms of all gathering agreements with KGS through 2020 and establishing a fixed gathering rate of $0.55 per Mcf for the gathering system in the Alliance Leasehold.

In September 2010, our board of directors approved a plan for disposal of the HCDS. As a result of this decision, we conducted an impairment analysis of the HCDS and recognized a charge for impairment.

We have continued to report our interests sold in the Crestwood Transaction and the HCDS as part of our continuing operating results because our use of their midstream services subsequent to closing of the Crestwood Transaction constitutes a "continuation of service" that precludes presentation of those businesses as discontinued operations under GAAP. The assets and liabilities of these midstream operations have been reclassified and are separately reported in our consolidated balance sheets.

The operating results of these midstream operations, as classified in our statement of income, are summarized below:

	For the Years Ended December 31, 2010	2009	2008
		(In thousands)	
Revenue	$ 13,119	$ 9,342	$ 12,521
Lease operating expense	-	-	-
PGT expense (1)	(57,679)	(74,196)	(47,697)
Ad valorem taxes	3,764	3,610	1,672
Other operations	3,444	5,233	738
DD&A	19,732	24,502	14,566
General and administrative expense	5,034	3,229	3,423
Impairment expense	28,611	-	-
Operating results of midstream operations	10,213	46,964	39,819
Interest and other expense	(6,916)	(4,764)	(1,339)
Results of midstream operations before income tax	3,297	42,200	38,480
Income tax expense	(1,265)	(15,428)	(12,836)
Results of midstream operations, net of income tax	$ 2,032	$ 26,772	$ 25,644

(1) Our KGS operations earned revenue from processing and gathering of our natural gas and NGL production. This revenue was consolidated as a reduction of processing, gathering and transportation expense for purposes of presenting our consolidated statements of income.

Details of balance sheet items for these midstream operations are summarized below:

	As of December 31, 2010	2009
		(In thousands)
Assets:		
Cash	$ -	$ 748
Accounts receivable, net	57	1,515
Other current assets	-	291
Property, plant and equipment, net	27,121	543,095
Other assets	-	2,859
Total	$ 27,178	$ 548,508
Liabilities		
Current liabilities	$ -	$ 11,226
Long-term debt	-	125,400
Other non-current liabilities	1,431	11,565
Total	$ 1,431	$ 148,191

2010 Lake Arlington Acquisition

In May 2010, we completed the acquisition of an additional 25% working interest in our company-operated Lake Arlington Project, for which we conveyed $62.1 million in cash and 3,619,901 BBEP Units owned by us with a market value of $54.4 million on the date of closing. We recognized a gain of $35.4 million as other income for the difference between our carrying value of $5.24 per BBEP Unit and the fair value of $15.03 per BBEP Unit on the date of the transaction.

2009 Eni Transaction

In June 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 that agreement and subsequent agreements, KGS will gather, treat and deliver Eni's Alliance Leasehold production. Eni also committed to pay $19.2 million to us for construction and installation of the facilities required to gather Eni's production from future Alliance Leasehold wells. KGS is now the sole owner of these facilities and is entitled to recognize gathering revenue for the volume 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. Through December 31, 2010 we had cumulatively completed 89,327 linear feet under the agreement compared with a contractual minimum of 86,663 feet. The prospective net linear footage requirements to be drilled and completed attributable to Eni are summarized below:

Year	Total Aggregate Linear Feet
2011	41,416
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.

2008 Alliance Acquisition

In August 2008, we completed the $1.3 billion Alliance Acquisition that consisted of producing and non-producing leasehold, royalty and midstream assets in the Barnett Shale. Consideration in the transaction was $1 billion in cash and $262 million of our common stock.

4. DERIVATIVES AND FAIR VALUE MEASUREMENTS

The following table details the estimated fair value of all derivative instruments where "Level 2" inputs are the basis of our fair value estimates at December 31, 2010 and 2009:

	As of December 31,	
	2010	2009
	(In thousands)	
Commodity contracts	$146,762	$107,881
Interest rate contracts	-	4,108
Gas Purchase Commitment	-	(6,625)
Total	$146,762	$105,364

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

Commodity Price Derivatives

As of December 31, 2010, we had price collars and swaps hedging our anticipated natural gas and NGL production as follows:

Production Year	Daily Production	
	Gas	NGL
	MMcfd	MBbld
2011	190	8
2012	130	-
2013	70	-
2014-2015	30	-

Since January 1, 2011, we have entered into two NGL price swaps for a total of 2.5 MBbld at a weighted average price of $40.45 per Bbl for 2011.

Interest Rate Derivatives

In June 2009, we entered into interest rate swaps on our $475 million senior notes due 2015 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 paid a variable interest rate and received the fixed rate applicable to the underlying debt. The interest income or expense was accrued as earned and recorded as an adjustment to the interest expense accrued on the fixed-rate debt. The interest rate swaps were 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 and a $4.1 million offsetting fair value adjustment to the debt hedged as of December 31, 2009. No ineffectiveness was recorded in connection with the fair value hedges. The 2010 and 2009 average effective interest rates on the 2015 Senior Notes were 6.5% and 5.1%, respectively. The 2010 and 2009 average effective interest rates on the Senior Subordinated Notes were 5.4% and 3.7%, respectively.

In February 2010, we executed the early settlement of the 2009 interest rate swaps that were designated as fair value hedges of our senior notes due 2015 and our senior subordinated notes. We received cash of $18.0 million in the settlement, including $3.7 million for interest previously accrued and earned, and recognized the remaining $14.3 million as a fair value adjustment to our debt.

In February 2010, we entered into new interest swaps to hedge the same debt instruments. We executed early settlement of a portion of the 2010 interest rate swaps in May 2010 and the remaining 2010 interest swaps in July 2010 for $6.8 million and $16.7 million, respectively. These settlements included $7.0 million for interest previously accrued and earned. The remaining cash of $16.5 million was recognized as a fair value adjustment to our debt.

The remaining deferral of these early settlements from all interest rate swaps will continue to be recognized as a reduction of interest expense over the life of the associated underlying debt instruments currently scheduled as follows:

(In thousands)	
2011	$ 4,897
2012	5,315
2013	5,769
2014	6,261
2015	4,824
2016	569
	$ 27,635

Gas Purchase Commitment

Based on information available on June 19, 2009, we recognized a liability pursuant to the Gas Purchase Commitment based on the estimated production volume attributable to Eni through December 31, 2010, which then totaled 22.2 Bcf. The Gas Purchase Commitment contained an embedded derivative that was adjusted to fair value throughout the period of the commitment, which expired on December 31, 2010. The following summarizes activity to the Gas Purchase Commitment:

	As of December 31,	
	2010	**2009**
	(In thousands)	
Beginning liability at fair value [1]	$ 50,744	$ 58,294
Decrease due to gas volumes purchased	(35,057)	(14,175)
Decrease due to changes in gas volumes	(9,062)	-
Embedded derivative	(6,625)	6,625
Ending liability at fair value	$ -	$ 50,744

[1] Initial valuation of the Gas Purchase Commitment was estimated using estimated Eni production volume 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, 2009 and 2010 were as follows:

	Asset Derivatives		Liability Derivatives	
	As of December 31,		As of December 31,	
	2010	2009	2010	2009
	(In thousands)		(In thousands)	
Derivatives designated as hedges:				
Commodity contracts reported in:				
Current derivative assets	$ 97,863	$ 97,883	$ 8,658	$ 638
Noncurrent derivative assets	63,419	11,031	5,862	-
Current derivative liabilities	-	243	-	638
Interest rate contracts reported in:				
Current derivative assets	-	712	-	-
Noncurrent derivative assets	-	3,396	-	-
Total derivatives designated as hedges	$ 161,282	$ 113,265	$ 14,520	$ 1,276
Derivatives not designated as hedges:				
Gas Purchase Commitment reported in accrued liabilities	$ -	$ -	$ -	$ 6,625
Total derivatives not designated as hedges	$ -	$ -	$ -	$ 6,625
Total derivatives	$ 161,282	$ 113,265	$ 14,520	$ 7,901

The increase in carrying value of our commodity price derivatives since December 31, 2009 principally resulted from the overall decline in market prices for natural gas relative to the prices in our open derivative instruments at December 31, 2010. These increases were partially offset by monthly settlements received during 2010.

The changes in the carrying value of our derivatives for 2010 and 2009 are presented below:

	For the Two Years Ended December 31, 2010				
	Michigan Contract	Gas Purchase Commitment (1)	Fair Value Derivatives	Cash Flow Derivatives	Total
			(In thousands)		
Derivative fair value at January 1, 2009	$ (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
Change in amounts receivable/payable-net	-	-	(9,180)	(3,451)	(12,631)
Net settlements reported in revenue	-	-	-	(190,504)	(190,504)
Net settlements reported in interest expense	-	-	(10,848)	-	(10,848)
Cash settlements reported in long-term debt	-	-	(30,816)	-	(30,816)
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	-	-	46,736	-	46,736
Ineffectiveness reported in other revenue	-	-	-	(2,629)	(2,629)
Unrealized gains reported in OCI	-	-	-	235,465	235,465
Derivative fair value at December 31, 2010	$ -	$ -	$ -	$ 146,762	$ 146,762

(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 during 2011 would result in a gain of $59.9 million net of income taxes. Hedge derivative ineffectiveness resulted in net losses of $2.6 million and $0.1 million for 2010 and 2009, respectively, and $1.6 million of net gains for 2008.

5. ACCOUNTS RECEIVABLE

Accounts receivable consisted of the following:

	As of December 31,	
	2010	2009
	(In thousands)	
Accrued production receivables	$ 36,144	$ 31,979
Joint interest receivables	8,172	12,636
Income tax receivable	17,368	7,018
Interest rate swap settlement receivable	-	9,180
Accrued production tax receivable	-	2,120
Other receivables	1,776	1,254
Allowance for doubtful accounts	(80)	(449)
	$ 63,380	$ 63,738

6. OTHER CURRENT ASSETS

Other current assets consisted of the following:

	As of December 31,	
	2010	2009
	(In thousands)	
Inventories	$ 27,388	$ 44,258
Prepaid production taxes	-	5,071
Deposits	597	2,758
Other prepaid expense	2,665	2,565
	$ 30,650	$ 54,652

7. INVESTMENT IN BBEP

At December 31, 2010, we owned 15.7 million BBEP Units, or 29%, of BBEP, whose price closed at $20.14 per unit as of that date. Note 3 contains additional information regarding the use of 3.6 million BBEP Units as partial consideration in the acquisition of oil and gas properties in May 2010. We further reduced our ownership September 2010 when we sold 1.4 million BBEP Units at a unit price of $16.22, net of fees paid. We recognized a gain of $14.4 million as other income for the difference between our carrying value at the time of the sale of $5.82 per BBEP unit and the net sales proceeds. In October 2010, we sold an additional 650,000 BBEP Units at a unit price of $17.72 and recognized a gain of $7.7 million.

We initially received 21.4 million BBEP Units as partial consideration of a portion of our U.S. oil and gas properties in November 2007. On June 17, 2008, BBEP announced that it had repurchased and retired 14.4 million BBEP Units, which represented 22% of the units previously outstanding. The resulting reduction in the number of BBEP Units outstanding increased our ownership at the time from 32% to 41%.

After obtaining our BBEP Units, we evaluated our investment for impairment in response to decreases in both prevailing commodity prices and the BBEP Unit price. We considered numerous factors in evaluating whether this was an other-than-temporary decline. As a result of the period during which BBEP Units traded below our net carrying value per unit, prevailing petroleum prices and broad limitations on available capital resulted in the determination that this was an other-than-temporary decline. 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 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 has occurred, although additional impairment of our investment in BBEP could occur in the future depending upon the performance of the BBEP 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, 2010	For the Twelve Months Ended September 30, 2009	For the Eleven Months Ended September 30, 2008
		(In thousands)	
Revenue [1]	$ 375,446	$ 609,846	$ 420,321
Operating expense [2]	285,394	380,197	251,618
Operating income	90,052	229,649	168,703
Interest and other [3]	24,903	45,714	27,795
Income tax (benefit) expense	(939)	323	593
Noncontrolling interests	146	27	206
Net income available to BBEP	$ 65,942	$ 183,585	$ 140,109
Net income available to common unitholders	$ 65,942	$ 183,585	$ 141,660

(1) For the twelve months ended September 30, 2010 and 2009, unrealized losses of $12.1 million and unrealized gains of $181.9 million on commodity derivatives were recognized. The eleven months of ended September 30, 2008 included $39.4 million of unrealized gains on commodity derivatives. 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, 2010 and 2009 included $5.2 million and $11.1 million, respectively, for unrealized losses on interest rate swaps. The eleven months ended September 30, 2008 included $2.3 million for unrealized losses on interest rate swaps.

	As of September 30, 2010	As of September 30, 2009
	(In thousands)	
Current assets	$ 145,233	$ 121,207
Property, plant and equipment	1,728,256	1,754,174
Other assets	98,113	114,673
Current liabilities	85,035	64,573
Long-term debt	516,000	585,000
Other non-current liabilities	64,715	72,519
Partners' equity	1,305,852	1,267,962

Changes in the balance of our investment in BBEP for 2010 and 2009 were as follows:

	As of December 31,	
	2010	2009
	(In thousands)	
Beginning investment balance	$ 112,763	$ 150,503
Equity income in BBEP	22,323	75,444
Distributions from BBEP	(20,905)	(11,100)
Disposal of BBEP Units	(30,840)	-
Non-cash impairment of BBEP	-	(102,084)
Ending investment balance	$ 83,341	$ 112,763

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

8. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consisted of the following:

	As of December 31,	
	2010	2009
	(In thousands)	
Oil and gas properties		
Subject to depletion	$ 4,805,161	$ 3,947,676
Unevaluated costs	314,543	458,037
Accumulated depletion	(2,274,785)	(2,067,469)
Net oil and gas properties	2,844,919	2,338,244
Other plant and equipment		
Pipelines and processing facilities	225,402	201,880
General properties	70,267	64,893
Accumulated depreciation	(72,743)	(62,172)
Net other property and equipment	222,926	204,601
Property, plant and equipment, net of accumulated depletion and depreciation	$ 3,067,845	$ 2,542,845

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. The charge for impairment in 2010 was recognized as a result of significant changes in our Canadian cost center for the initial producing wells in our Horn River Asset and associated field costs while proved reserves recognized were limited because of the short production history for the area. We recognized charges for impairment of both our U.S. and Canadian cost centers during 2009 and our U.S. cost center during 2008 due to significant decreases in natural gas and NGL market prices. The 2008 charge for impairment of our U.S. cost center was also due, in part, to our determination 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. The charges for impairment are summarized below:

	Pre-tax Charges for Impairment		
	2010	2009	2008
		(In thousands)	
U.S.	$ -	$ 786,867	$ 624,315
Canada	19,386	192,673	-
	$ 19,386	$ 979,540	$ 624,315

In September 2010, our board of directors approved a plan for disposal of the HCDS. As a result of the decision, we conducted an impairment analysis of the HCDS and recognized a $28.6 million charge for impairment.

We also conducted an analysis of our midstream assets in West Texas for impairment in 2008 in conjunction with our evaluation of our exploration of the Delaware Basin in West Texas, and recorded an impairment charge of $9.2 million 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, 2010 and 2009 and the year in which they were incurred follows:

	December 31, 2010 Costs Incurred During					December 31, 2009 Costs Incurred During				
	2010	2009	2008	Prior	Total	2009	2008	2007	Prior	Total
			(In thousands)					(In thousands)		
Acquisition costs	$ 42,117	$ 7,482	$ 111,929	$ 76,192	$ 237,720	$ 12,175	$ 275,611	$ 54,511	$ 63,089	$ 405,386
Exploration costs	36,383	21,531	7,616	-	65,530	29,029	16,470	-	-	45,499
Capitalized interest	4,874	2,866	3,553	-	11,293	3,598	3,554	-	-	7,152
Total	$ 83,374	$ 31,879	$ 123,098	$ 76,192	$ 314,543	$ 44,802	$ 295,635	$ 54,511	$ 63,089	$ 458,037

The following table summarizes the regions where we have unevaluated property costs not subject to depletion.

	As of December 31,	
	2010	2009
	(In thousands)	
Barnett Shale	$ 121,854	$ 312,892
Horn River	160,663	117,565
Greater Green River Basin	30,688	27,131
Other	1,338	449
Total	$ 314,543	$ 458,037

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 $17.7 million, $17.1 million and $16.8 million for 2010, 2009 and 2008, respectively. Depletion per Mcfe was $1.27, $1.36 and $1.68 for 2010, 2009 and 2008, respectively.

9. OTHER ASSETS

Other assets consisted of the following:

	As of December 31,	
	2010	2009
	(In thousands)	
Deferred financing costs	$ 60,233	$ 57,122
Less accumulated amortization	(22,222)	(13,451)
Net deferred financing costs	38,011	43,671
Other	230	233
	$ 38,241	$ 43,904

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

10. ACCRUED LIABILITIES

Accrued liabilities consisted of the following:

	As of December 31,	
	2010	2009
	(In thousands)	
Interest payable	$ 69,394	$ 71,107
Gas Purchase Commitment liability	-	50,744
Accrued operating expenses	34,136	18,790
Prepayments from partners	4,490	5,224
Revenue payable	5,563	4,141
Accrued state income and franchise taxes	4,497	60
Accrued production and property taxes	2,448	2,157
Environmental liabilities	235	659
Accrued product purchases	345	483
Current asset retirement obligations	1,574	109
Other	222	124
	$ 122,904	$ 153,598

11. LONG-TERM DEBT

Long-term debt consisted of the following:

	As of December 31, 2010	As of December 31, 2009
	(In thousands)	
Senior Secured Credit Facility	$ 21,114	$ 467,569
Senior notes due 2015, net of unamortized discount of $4,134 and $5,036	470,866	469,964
Senior notes due 2016, net of unamortized discount of $16,395 and $18,641	583,605	581,359
Senior notes due 2019, net of unamortized discount of $6,504 and $6,996	293,496	293,004
Senior subordinated notes due 2016	350,000	350,000
Convertible debentures, net of unamortized discount of $6,522 and $13,881	143,478	136,119
Total debt	1,862,559	2,298,015
Unamortized deferred gain – terminated interest rate swaps	27,635	-
Fair value of interest rate swaps	-	4,108
Current portion of long-term debt	(143,478)	-
Long-term debt	$ 1,746,716	$ 2,302,123

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
				(In thousands)			
2011	$ 150,000	$ -	$ -	$ -	$ -	$ -	$ 150,000
2012	-	-	-	-	-	-	-
2013	21,114	21,114	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	475,000	-	475,000	-	-	-	-
Thereafter	1,250,000	-	-	600,000	300,000	350,000	-
	$ 1,896,114	$ 21,114	$ 475,000	$ 600,000	$ 300,000	$ 350,000	$ 150,000

Senior Secured Credit Facility

During the fourth quarter of 2010, our Senior Secured Credit Facility maturity was extended by one year and now matures on February 9, 2013. The Senior Secured Credit Facility availability is governed by a borrowing base and determined annually by the lenders taking into consideration the estimated value of oil and gas properties and any other relevant information all in accordance with their customary practices for oil and gas loans in effect from time to time. At December 31, 2010 the borrowing base and commitments were $1.0 billion and the aggregate letter of credit capacity was $175 million. The Senior Secured Credit Facility provides us an option to increase availability by up to $250 million, with a maximum of $1.45 billion with lender consents and additional commitments. We can also extend the maturity date 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 lesser of the borrowing base or commitments.
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, substantially all of our oil and gas properties. We have also pledged a portion of our equity interests in BBEP to secure our obligations under the Senior Secured Credit Facility. At December 31, 2010, there was $930 million available under the facility. Our ability to remain in compliance with the financial covenants in our credit facilities 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

In June 2008, we issued $475 million of senior notes due 2015, which are unsecured, senior obligations of Quicksilver. The notes were issued at 98.66% of par. Interest at the rate of 8.25% is payable semiannually on February 1 and August 1.

Senior Notes Due 2016

In June 2009, we issued $600 million of senior notes due 2016, which are unsecured, senior obligations. The notes were issued at 96.72% 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

In August 2009, we issued $300 million of senior notes due 2019, which are unsecured, senior obligations. The notes were issued at 97.61% 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 Subordinated Notes

In 2009, we issued $350 million of senior subordinated notes due 2016. The senior subordinated notes are unsecured, senior subordinated obligations 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 our 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 our 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 including certain changes of control, holders of the debentures are not entitled to exercise their conversion rights unless the closing price of our stock 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 our common stock and cash. Should all debentures be converted to our common stock, an additional 9,816,270 shares would become outstanding; however, as of January 1, 2011, the debentures were not convertible based on share prices for the quarter ended December 31, 2010. In addition, upon a conversion in connection with certain changes in control, additional shares may be issuable if the transaction price is between $10.72 and $37.03 per share.

Because we may be required to repurchase these obligations at the option of the holders on November 1, 2011, we have reported them as current obligations in our December 31, 2010 balance sheet. To the extent that the holders of these obligations do not elect to put them on November 1, 2011, any remaining obligations will be reclassified to long-term after that date.

Summary of All Outstanding Debt

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

	Priority on Collateral and Structural Seniority[2]					
	Highest priority	←		→		Lowest priority
		Equal priority				
	Senior Secured Credit Facility	**2015 Senior Notes**	**2016 Senior Notes**	**2019 Senior Notes**	**Senior Subordinated Notes**	**Convertible Debentures[1]**
Principal amount	\$1.0 billion[3]	\$475 million	\$600 million	\$300 million	\$350 million	\$150 million
Scheduled maturity date [5]	February 9, 2013	August 1, 2015	January 1, 2016	August 15, 2019	April 1, 2016	November 1, 2024
Interest rate on outstanding borrowings at December 31, 2010 [4]	4.125%	8.25%	11.75%	9.125%	7.125%	1.875%
Base interest rate options	LIBOR, ABR or specified[5]	N/A	N/A	N/A	N/A	N/A
Financial covenants [5]	-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
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
Optional redemption [6]	Any time	August 1, 2012: 103.875 2013: 101.938 2014: par	July 1, 2013: 105.875 2014: 102.938 2015: par	August 15, 2014: 104.563 2015: 103.042 2016: 101.521 2017: par	April 1, 2011: 103.563 2012: 102.375 2013: 101.188 2014: par	November 8, 2011 and thereafter
Make-whole redemption [6]	N/A	Callable prior to August 1, 2012 at make-whole call price of Treasury + 50 bps	Callable prior to July 1, 2013 at make-whole call price of Treasury + 50 bps	Callable prior to August 15, 2014 at make-whole call price of Treasury + 50 bps	Callable prior to April 1, 2011 at make-whole call price of Treasury + 50 bps	N/A
Change of control [6]	Event of default	Put at 101% of principal plus accrued interest	Put at 101% of principal plus accrued interest	Put at 101% of principal plus accrued interest	Put at 101% of principal plus accrued interest	Put at 100% of principal plus accrued interest
Equity clawback [6]	N/A	Redeemable until August 1, 2011 at 107.75%, plus accrued interest for up to 35%	Redeemable until July 1, 2012 at 111.75%, plus accrued interest for up to 35%	Redeemable until August 15, 2012 at 109.125%, plus accrued interest for up to 35%	N/A	N/A
Subsidiary guarantors [6]	Cowtown Pipeline Funding , Inc. Cowtown Pipeline Management, Inc. Cowtown Pipeline L.P. Cowtown Gas Processing L.P. Quicksilver Resources Canada Inc.	Cowtown Pipeline Funding , Inc. Cowtown Pipeline Management, Inc. Cowtown Pipeline L.P. Cowtown Gas Processing L.P.	Cowtown Pipeline Funding , Inc. Cowtown Pipeline Management, Inc. Cowtown Pipeline L.P. Cowtown Gas Processing L.P.	Cowtown Pipeline Funding , Inc. Cowtown Pipeline Management, Inc. Cowtown Pipeline L.P. Cowtown Gas Processing L.P.	Cowtown Pipeline Funding , Inc. Cowtown Pipeline Management, Inc. Cowtown Pipeline L.P. Cowtown Gas Processing L.P.	N/A
Estimated fair value [7]	\$21.1 million	\$490.4 million	\$699.0 million	\$327.0 million	\$332.5 million	\$165.2 million

(1) As discussed in "Convertible Debentures" above, holders of the convertible debentures can require us to repurchase all or a part of the debentures on November 1, 2011.

(2) The Senior Secured Credit Facility is secured by a first perfected lien on substantially all our assets including a portion of our BBEP Units. The other debt presented is based upon structural seniority and priority of payment.

(3) The principal amount for the Senior Secured Credit Facility represents the borrowing base and commitments as of December 31, 2010.

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

(5) Amounts outstanding under the Senior Secured Credit Facility bear interest, at our election, at (i) LIBOR plus an applicable margin between 2.00% to 3.00%, (ii) ABR, which is the greatest of (a) the prime rate announced by JPMorgan, (b) the federal funds rate plus 0.50% and (c) the Adjusted Eurodollar Rate (as defined in the credit facilities) plus 1.0%, plus, in each case under scenario (ii), an applicable margin between 1.125% to 2.125%, or (iii) the specified rate (as defined in the credit facilities) plus an applicable margin between 2.00% to 3.00%.

(6) The information presented in this table is qualified in all respects by reference to the full text of the covenants, provisions 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.

12. ASSET RETIREMENT OBLIGATIONS

The following table provides a reconciliation of the changes in the estimated asset retirement obligation from January 1, 2009 through December 31, 2010.

	As of December 31,	
	2010	2009
	(In thousands)	
Beginning asset retirement obligations	$ 48,581	$ 29,960
Additional liability incurred	2,440	1,420
Change in estimates	2,042	12,916
Accretion expense	2,568	1,909
Sale of properties	-	(380)
Asset retirement costs incurred	(1,184)	(379)
Gain on settlement of liability	1,264	132
Currency translation adjustment	2,098	3,003
Ending asset retirement obligations	57,809	48,581
Less current portion	(1,574)	(109)
Long-term asset retirement obligation	$ 56,235	$ 48,472

13. INCOME TAXES

Our current and deferred tax positions were significantly impacted by the 2008 and 2009 impairments of our oil and gas properties and our investment in BBEP. Significant components of our deferred tax assets and liabilities as of December 31, 2010 and 2009 are as follows:

	As of December 31,	
	2010	2009
Deferred tax assets:	(In thousands)	
Net operating loss carry forwards	$ 98,870	$ 290,894
AMT tax credit	67,633	-
Cash flow hedge settlements	-	19,214
Interest rate swap settlements	9,672	-
Deferred compensation expense	8,401	10,654
Other	7,028	8,712
Deferred tax assets	191,604	329,474
Deferred tax liabilities:		
Property, plant and equipment	(292,146)	(185,889)
Cash flow hedge gains	(49,153)	(55,372)
BBEP investment	(16,545)	(29,398)
Convertible debenture interest	(19,604)	(18,588)
Deferred tax liabilities	(377,448)	(289,247)
Total deferred tax asset (liability)	$ (185,844)	$ 40,227
Reflected in the consolidated balance sheets as:		
Non-current deferred income tax asset	$ -	$ 133,051
Current deferred income tax liability	(28,861)	(51,675)
Non-current deferred income tax liability	(156,983)	(41,149)
	$ (185,844)	$ 40,227

No rate changes occurred in any taxing jurisdiction for 2008, 2009 or 2010. For 2011 and beyond, we have utilized a rate of 25% in Canada and a federal rate of 35% and a state rate of 1% in the U.S. to value our deferred tax positions, with the U.S. federal and state future rates mirroring existing applicable rates.

The components of income tax expense for 2010, 2009 and 2008 are as follows:

	2010	2009	2008
		(In thousands)	
Current state income tax expense (benefit)	$ 4,501	$ (2)	$ (4)
Current U.S. federal income tax expense (benefit)	67,632	(202)	(45,210)
Current Canadian income tax expense	1,038	-	199
Total current income tax expense (benefit)	73,171	(204)	(45,015)
Deferred state income tax expense (benefit)	3,674	(4,928)	1,939
Deferred U.S. federal income tax expense (benefit)	173,748	(262,217)	(190,938)
Deferred Canadian income tax expense (benefit)	2,293	(24,268)	22,559
Total deferred income tax expense (benefit)	179,715	(291,413)	(166,440)
Total income tax expense (benefit)	$ 252,886	$ (291,617)	$ (211,455)

The following table reconciles the statutory federal income tax rate to the effective tax rate for 2010, 2009 and 2008:

	2010	2009	2008
U.S. federal statutory tax rate	35.00%	35.00%	35.00%
Permanent differences	0.79%	(0.18%)	(0.33%)
Noncontrolling interest benefit (expense)	(0.49%)	0.71%	-
State income taxes net of federal deduction	0.77%	0.38%	(0.22%)
Recognition of uncertain tax position	-	-	(0.09%)
Foreign income taxes	0.19%	(0.98%)	1.38%
Other	(0.01%)	(0.08%)	0.40%
Effective income tax rate	36.25%	34.85%	36.14%

We incurred net operating tax losses of $336 million and $656 million in 2009 and 2008, respectively, of which $138 million of this loss was carried back to 2007. A portion of the remaining $854 million has been applied to our 2010 taxable income and the remainder is included in deferred tax assets at December 31, 2010. Our net operating losses will expire in 2029 and 2030. 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 have not been reduced by a valuation allowance, because we believe 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 October 2009, the IRS commenced an audit of our 2007 and 2008 consolidated U.S. federal income tax returns. No significant adjustments have been proposed by the IRS for those years. The Joint Committee of Taxation is required to review the net operating loss carrybacks we filed in 2009, which may delay the completion of the 2007 and 2008 audits until the third quarter of 2011. We remain subject to examination by the IRS for the years 2001 through 2006 except for 2004. An audit was completed by the IRS for 2004 and the statute of limitations has now expired for that year.

The following schedule reconciles the total amounts of unrecognized tax benefits for 2010 and 2009.

	As of December 31, 2010	As of December 31, 2009
	(In thousands)	
Beginning unrecognized tax benefits	$ 9,219	$ 9,255
Gross amounts of decreases in unrecognized tax benefits as a result of tax positions taken during the current year	-	(36)
Unrecognized tax benefits	$ 9,219	$ 9,219

At December 31, 2010, $8.9 million of these unrecognized tax benefits, if recognized, would impact the effective tax rate. We do not expect that the total amounts of unrecognized tax benefits will significantly increase or decrease over the next twelve months.

14. COMMITMENTS AND CONTINGENCIES

Contractual Obligations.

Information regarding our contractual obligations, at December 31, 2010, is set forth in the following table.

	GPT Contracts (1)	Drilling Rig Contracts (2)	Operating Leases (3)	Purchase Obligations (4)
	(In thousands)			
2011	$ 44,315	$ 31,827	$ 3,301	$ 1,136
2012	59,005	23,360	4,388	-
2013	68,980	791	3,752	-
2014	59,336	-	3,681	-
2015	57,119	-	3,686	-
Thereafter	125,549	-	21,642	-
Total	$ 414,304	$ 55,978	$ 40,450	$ 1,136

(1) Under contracts with various third parties, we are obligated to provide minimum daily natural gas volume for gathering, processing, fractionation and transportation, as determined on a monthly basis, or pay for any deficiencies at a specified reservation fee rate. Our available production committed to third parties is expected to exceed the daily volume required under the contracts. Our gathering and transportation contracts with KGS have no minimum volume requirement and, therefore, are not reported in the above amounts.

(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 $20,000 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 $4.3 million in 2010, $4.1 million in 2009 and $5.0 million in 2008.

(4) At December 31, 2010, we were under contract to purchase goods and services related to field operations and construction of midstream assets in the Horn River Basin.

Commitments

At December 31, 2010, we had $39.4 million in surety bonds issued to fulfill contractual, legal or regulatory requirements and $49.2 million in letters of credit outstanding against the credit facility, including $28.9 million issued to provide credit support for surety bonds. Surety bonds and letters of credit generally have an annual renewal option.

Contingencies

Our lawsuit filed October 13, 2006 against Eagle Drilling LLC ("Eagle") as well as Eagle Domestic Drilling Operations, LLC ("EDDO"), 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. EDDO is no longer a party in this case. In September 2008, we entered into a settlement agreement with EDDO and its parent, Blast Energy Services Inc. ("Blast") that was approved in the court in October 2008. Under the settlement agreement, we agreed to pay EDDO/Blast $10 million over a three-year period, including $5 million on the settlement date. 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. On October 19, 2010, the Court granted our motion for summary judgment directed to Eagle's breach of contract claims and denied Eagle's motions to strike. Currently, our motions for summary judgment on Eagle's other claims remain pending with the Court, who vacated its October 29, 2010 docket call for trial in order to have additional time to consider such motions. We will continue to assert 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 the District Court of Cleveland County, Oklahoma (the "Eagle Oklahoma Case") for damages, including 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 September 8, 2010, our Executive Vice President - Operations was charged with perjury in Cleveland County, Oklahoma based upon an affidavit Mr. Cook executed in a lawsuit brought against us in Cleveland County that was later dismissed and an affidavit Mr. Cook subsequently executed in the Eagle Oklahoma suit. We and our Executive Vice President - Operations deny the allegations of perjury. Mr. Cook will plead not guilty and will vigorously defend himself against the charges.

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, 2010, we had recorded $0.2 million for liabilities for environmental matters.

15. NONCONTROLLING INTERESTS AND KGS

KGS issued 4,000,000 newly issued common units in December 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. In January 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%. 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.

With the closing of the Crestwood Transaction, we no longer consolidate the KGS operations or financial position in our financial statements. Accordingly, we no longer have noncontrolling interests within our financial statements either.

16. QUICKSILVER STOCKHOLDERS' EQUITY

Common Stock, Preferred Stock and Treasury Stock

We are authorized to issue 400 million shares of common stock with a $0.01 par value per share and 10 million shares of preferred stock with a $0.01 par value per share. At December 31, 2010, we had 170.5 million shares of common stock outstanding.

The following table shows common share and treasury share activity since January 1, 2008:

	Common Shares Issued	Treasury Shares Held
Balance at January 1, 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
Stock options exercised	336,629	16,908
Restricted stock activity	718,351	329,094
Balance at December 31, 2010	175,524,816	5,050,450

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 our common stock 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 common stock. This 15% threshold does not apply to certain members of the Darden family and affiliated entities, which collectively owned, directly or indirectly, approximately 32% of our common stock at February 16, 2011.

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 our common shares having a market value of twice such price. If we are 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, under which 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. In May 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, 2010 and 2009, 14.1 million shares and 15.1 million shares (including 0.6 million shares and 0.2 million shares, respectively, surrendered to us to satisfy participants' tax withholding obligations which then became available for future issuance under the 2006 Equity Plan), respectively, were available for issuance under the 2006 Equity Plan.

Stock Options

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

	2010	2009	2008
Wtd avg grant date fair value	$9.88	$3.36	$13.67
Wtd avg grant date	Jan 4, 2010	Jan 2, 2009	Jan 2, 2008
Wtd avg risk-free interest rate	3.00%	1.90%	3.41%
Expected life (in years)	6.0	6.0	6.0
Wtd avg volatility	66.76%	56.76%	40.2%
Expected dividends	-	-	-

The following table summarizes our stock option activity for 2010:

	Shares	Wtd Avg Exercise Price	Wtd Avg Remaining Contractual Life	Aggregate Intrinsic Value (In thousands)
Outstanding at January 1, 2010	3,014,441	$ 8.97		
Granted	901,887	15.88		
Exercised	(336,629)	5.99		
Cancelled	(231,057)	9.48		
Outstanding at December 31, 2010	3,348,642	$ 11.10	8.1	$18,511
Exercisable at December 31, 2010	981,418	$ 12.25	7.5	$ 6,069

We estimate that a total of 3,281,902 stock options will become vested including those options already exercisable. These unexercised options have a weighted average exercise price of $11.13 and a weighted average remaining contractual life of 8.1 years.

Compensation expense related to stock options of $6.7 million, $4.5 million and $1.6 million was recognized for 2010, 2009 and 2008, respectively. Cash received from the exercise of stock options totaled $1.8 million, $4.0 million and $1.2 million for the years 2010, 2009 and 2008, respectively. The total intrinsic value of options exercised during 2010, 2009 and 2008, was $2.8 million, $4.3 million and $6.7 million, respectively.

Restricted Stock

The following table summarizes our restricted stock and stock unit activity for 2010:

	Payable in shares		Payable in cash	
	Shares	Wtd Avg Grant Date Fair Value	Shares	Wtd Avg Grant Date Fair Value
Outstanding at January 1, 2010	2,722,875	$ 10.33	328,695	$ 6.22
Granted	892,069	15.58	217,244	14.40
Vested	(1,115,293)	12.32	(109,602)	6.22
Cancelled	(170,562)	11.98	(63,704)	10.20
Outstanding at December 31, 2010	2,329,089	$ 11.27	372,633	$ 10.31

At December 31, 2009, we had unrecognized compensation cost related to outstanding unvested restricted stock of $15.1 million. As of December 31, 2010, the unrecognized compensation cost related to outstanding unvested restricted stock was $13.9 million, which is expected to be recognized in expense over the next 2 years. Grants of restricted stock and stock units during 2010 had an estimated grant date fair value of $13.1 million. The fair value of RSUs settled in cash was $5.5 million and $4.9 million at December 31, 2010 and 2009, respectively. For 2010, 2009 and 2008, compensation expense of $13.3 million, $14.6 million and $13.5 million, respectively, was recognized. The total fair value of shares vested during 2010, 2009 and 2008 was $16.4 million, $11.0 million and $15.1 million, respectively.

17. 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,		
	2010	2009	2008
	(In thousands, except per share data)		
Net income (loss) attributable to Quicksilver	$435,069	$(557,473)	$(378,276)
Basic income allocable to participating securities [(1)]	(5,563)	—	—
Basic net income (loss) attributable to Quicksilver	$429,506	$(557,473)	$(378,276)
Impact of assumed conversions — interest on 1.875% convertible debentures, net of income taxes	7,194	—	—
Income (loss) available to stockholders assuming conversion of convertible debentures	$436,700	$(557,473)	$(378,276)
Weighted average common shares — basic	168,010	169,004	162,004
Effect of dilutive securities [(2)]:			
Share-based compensation awards	801	—	—
Contingently convertible debentures	9,816	—	—
Weighted average common shares — diluted	178,628	169,004	162,004
Earnings (loss) per common share — basic	$ 2.56	$ (3.30)	$ (2.33)
Earnings (loss) per common share — diluted	$ 2.45	$ (3.30)	$ (2.33)

(1) Unvested restricted share awards that contain nonforfeitable rights to dividends are participating securities and, therefore, should be included in computing earnings using the two-class method. Participating securities, however, do not participate in undistributed net losses because there is no contractual obligation to do so.

(2) For 2010, no outstanding options were excluded from the diluted net income per share calculation; however, 0.1 million restricted shares were excluded from the diluted net income per share calculation

as they were antidilutive. For 2009 and 2008, the effects of convertible debt of 9.8 million shares and all shared-based compensation awards were antidilutive and, therefore, excluded from the diluted share calculations.

18. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The following tables provide information about the entities that guarantee our 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 our 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:

Guarantor Subsidiaries - Restricted	Non-Guarantor Subsidiaries	
	Restricted	Unrestricted
Cowtown Pipeline Funding, Inc.	Quicksilver Resources Canada Inc.	Quicksilver Gas Services Holdings LLC [3]
Cowtown Pipeline Management, Inc.	Cowtown Drilling Inc. [1]	Quicksilver Gas Services GP LLC [3]
Cowtown Pipeline L.P.	Quicksilver Resources Horn River Inc. [2]	Quicksilver Gas Services LP [3]
Cowtown Gas Processing L.P.		Quicksilver Gas Services Operating LLC [3]
		Quicksilver Gas Services Operating GP LLC [3]
		Cowtown Pipeline Partners L.P. [3]
		Cowtown Gas Processing Partners L.P. [3]

(1) This entity was inactive for the three-year period ended December 31, 2010.

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

(3) We sold all our interests in this entity to Crestwood on October 1, 2010.

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 indentures 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. The 2010, 2009 and 2008 condensed consolidating financial information includes changes in the financial information of our unrestricted non-guarantor subsidiaries to present the 2010, 2009 and 2008 financial information including the effects of the purchase of Alliance Midstream Assets by KGS and the Crestwood Transaction where we sold all of our interests in the unrestricted subsidiaries.

Condensed Consolidating Balance Sheets

	December 31, 2010							
	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	$ 210,652	$ 86,582	$ 49,424	$ (108,486)	$ 238,172	$ -	$ -	$ 238,172
Property and equipment	2,417,680	68,390	581,775	-	3,067,845	-	-	3,067,845
Assets of midstream operations	-	27,178	-	-	27,178	-	-	27,178
Investment in subsidiaries (equity method)	611,465	-	(243,620)	(284,504)	83,341	-	-	83,341
Other assets	95,607	-	191	-	95,798	-	-	95,798
Total assets	$ 3,335,404	$ 182,150	$ 387,770	$ (392,990)	$ 3,512,334	$ -	$ -	$ 3,512,334
LIABILITIES AND EQUITY								
Current liabilities	$ 411,586	$ 106,627	$ 53,373	$ (108,486)	$ 463,100	$ -	$ -	$ 463,100
Long-term liabilities	1,864,410	20,346	103,639	-	1,988,395	-	-	1,988,395
Liabilities of midstream operations	-	1,431	-	-	1,431	-	-	1,431
Quicksilver stockholders' equity	1,059,408	53,746	230,758	(284,504)	1,059,408	-	-	1,059,408
Total liabilities and equity	$ 3,335,404	$ 182,150	$ 387,770	$ (392,990)	$ 3,512,334	$ -	$ -	$ 3,512,334

	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	$ 296,233	$ 109	$ 42,622	$ (121,580)	$ 217,384	$ -	$ -	$ 217,384
Property and equipment	1,980,053	71,264	491,528	-	2,542,845	-	-	2,542,845
Assets of midstream operations	55,717	291,104	-	-	346,821	502,401	(300,714)	548,508
Investment in subsidiaries (equity method)	549,200	-	-	(436,437)	112,763	-	-	112,763
Other assets	182,062	-	3,112	-	185,174	6,208	-	191,382
Total assets	$ 3,063,265	$ 362,477	$ 537,262	$ (558,017)	$ 3,404,987	$ 508,609	$ (300,714)	$ 3,612,882
LIABILITIES AND EQUITY								
Current liabilities	$ 334,638	$ 117,055	$ 25,321	$ (121,580)	$ 355,434	$ -	$ -	$ 355,434
Long-term liabilities	2,092,629	9,966	309,840	-	2,412,435	-	-	2,412,435
Liabilities of midstream operations	-	1,120	-	-	1,120	217,564	(70,493)	148,191
Quicksilver stockholders' equity	635,998	234,336	202,101	(436,437)	635,998	230,221	(230,221)	635,998
Noncontrolling interests	-	-	-	-	-	60,824	-	60,824
Total liabilities and equity	$ 3,063,265	$ 362,477	$ 537,262	$ (558,017)	$ 3,404,987	$ 508,609	$ (300,714)	$ 3,612,882

Condensed Consolidating Statements of Income

For the Year Ended December 31, 2010	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
	(In thousands)							
Revenue	$ 788,714	$ 6,863	$ 126,322	$ (3,197)	$ 918,702	$ 82,299	$ (72,670)	$ 928,331
Operating expenses	489,773	37,508	113,768	(3,197)	637,852	48,368	(72,670)	613,550
Gain on sale of subsidiary	473,204	-	-	-	473,204	-	-	473,204
Equity in net earnings of subsidiaries	(7,666)	15,228	-	7,666	15,228	-	(15,228)	-
Operating income (loss)	764,479	(15,417)	12,554	7,666	769,282	33,931	(15,228)	787,985
Income from earnings of BBEP	22,323	-	-	-	22,323	-	-	22,323
Interest expense and other	(96,953)	-	(6,868)	-	(103,821)	(8,808)	-	(112,629)
Income tax (expense) benefit	(254,780)	5,396	(3,331)	-	(252,715)	(171)	-	(252,886)
Net income (loss)	$ 435,069	$ (10,021)	$ 2,355	$ 7,666	$ 435,069	$ 24,952	$ (15,228)	$ 444,793
Net income attributable to noncontrolling interests	-	-	-	-	-	(9,724)	-	(9,724)
Net income (loss) attributable to Quicksilver	$ 435,069	$ (10,021)	$ 2,355	$ 7,666	$ 435,069	$ 15,228	$ (15,228)	$ 435,069

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	Consolidated Eliminations	Quicksilver Resources Inc. Consolidated
	(In thousands)							
Revenue	$ 634,321	$ 4,395	$ 188,769	$ (2,014)	$ 825,471	$ 91,706	$ (84,442)	$ 832,735
Operating expenses	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							
	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)							
Revenue	$ 600,906	$ 514	$ 187,126	$ (426)	$ 788,120	$ 76,084	$ (63,563)	$ 800,641
Operating expenses	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)

Condensed Consolidating Statements of Cash Flows

	For the Year Ended December 31, 2010							
	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	$ 44,544	$ 651	$ 322,579	$ -	$ 367,774	$ 44,816	$ (14,870)	$ 397,720
Purchases of property, plant and equipment	(534,404)	(651)	(100,183)	-	(635,238)	(52,470)	(7,406)	(695,114)
Distribution to parent	80,276	-	-	-	80,276	(80,276)	-	-
Proceeds from sale of KGS	699,973	-	-	-	699,973	-	-	699,973
Proceeds from sale of BBEP units	34,016	-	-	-	34,016	-	-	34,016
Proceeds from sale of properties and equipment	9,953	-	-	-	9,953	-	-	9,953
Net cash flow used for investing activities	289,814	(651)	(100,183)	-	188,980	(132,746)	(7,406)	48,828
Issuance of debt	478,500	-	68,358	-	546,858	143,200	-	690,058
Repayments of debt	(712,000)	-	(289,636)	-	(1,001,636)	(30,100)	-	(1,031,736)
Debt issuance costs	(2,211)	-	(900)	-	(3,111)	-	-	(3,111)
Gas Purchase Commitment repayments	(44,119)	-	-	-	(44,119)	-	-	(44,119)
Issuance of KGS common units	-	-	-	-	-	11,054	-	11,054
Distributions to parent	-	-	-	-	-	(22,276)	22,276	-
Distributions to noncontrolling interests	-	-	-	-	-	(13,550)	-	(13,550)
Proceeds from exercise of stock options	1,801	-	-	-	1,801	-	-	1,801
Excess tax benefits on exercise of stock options	3,513	-	-	-	3,513	-	-	3,513
Taxes paid on vested KGS equity compensation	-	-	-	-	-	(1,144)		(1,144)
Purchase of treasury stock	(4,910)	-	-	-	(4,910)	-	-	(4,910)
Net cash flow provided by (used for) financing activities	(279,426)	-	(222,178)	-	(501,604)	87,184	22,276	(392,144)
Effect of exchange rates on cash	-	-	(1,252)	-	(1,252)	-	-	(1,252)
Net decrease in cash and equivalents	54,932	-	(1,034)	-	53,898	(746)	-	53,152
Cash and equivalents at beginning of period	5	-	1,034	-	1,039	746	-	1,785
Cash and equivalents at end of period	$ 54,937	$ -	$ -	$ -	$ 54,937	$ -	$ -	$ 54,937

	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	$ 358,405	$ 73,202	$ 148,280	$ -	$ 579,887	$ 68,133	$ (35,717)	$ 612,303
Purchases of property, plant and equipment	(474,659)	(73,202)	(94,209)	-	(642,070)	(54,818)	3,050	(693,838)
Proceeds from sale of properties 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
Taxes paid on vested KGS equity compensation	-	-	-	-	-	(63)	-	(63)
Purchase of treasury stock	(922)	-	-	-	(922)	-	-	(922)
Net cash flow provided by (used for) financing activities	(105,626)	-	(57,560)	-	(163,186)	(12,872)	32,667	(143,391)
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 sale of properties 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

19. SEGMENT INFORMATION

We operate in two geographic segments, the U.S. and Canada, where we are engaged in the exploration and production segment of the oil and gas industry. Additionally, prior to the Crestwood Transaction, we operated in the midstream segment in the U.S., where we provided natural gas gathering and processing services predominantly through KGS. Revenue earned by KGS prior to the Crestwood Transaction for the gathering and processing of our gas have been eliminated on a consolidated basis as is the GPT recognized by our producing properties. We evaluate performance based on operating income and property and equipment costs incurred.

	Exploration & Production		Processing &			Quicksilver
	U.S.	Canada	Gathering	Corporate	Elimination	Consolidated
			(In thousands)			
2010						
Revenue	$ 788,714	$ 126,322	$ 87,426	$ -	$ (74,131)	$ 928,331
DD&A	131,761	45,335	23,523	1,984	-	202,603
Impairment expense	-	19,386	28,611	-	-	47,997
Operating income (loss)	841,021	16,765	12,290	(82,091)	-	787,985
Investment in equity affiliates	83,341	-	-	-	-	83,341
Property, plant and equipment - net	2,403,039	581,775	68,389	14,642	-	3,067,845
Property and equipment costs incurred	452,044	123,348	154,271	5,146	-	734,809
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 expense	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	71,264	11,623	-	2,542,845
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 expense	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	20,562	11,101	-	3,298,830
Property and equipment costs incurred	2,173,469	138,360	265,222	7,984	-	2,585,035

20. SUPPLEMENTAL CASH FLOW INFORMATION

Cash paid (received) for interest and income taxes is as follows:

	Years Ended December 31,		
	2010	2009	2008
		(In thousands)	
Interest	$ 136,459	$ 128,217	$ 83,400
Income taxes	78,083	(41,267)	49,433

Other significant non-cash transactions are as follows:

	Years Ended December 31,		
	2010	2009	2008
		(In thousands)	
Working capital related to capital expenditures	$ 100,587	$ 118,294	$ 230,624
Issuance of common stock as consideration for the			
Alliance Acquisition	-	-	262,092
Conveyance of 3,619,901 BBEP common units		-	-
for producing properties	54,407	-	-
Quicksilver common shares received for cashless exercise of 34,415 stock options	214	-	-

21. 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. Expense associated with company contributions was $2.5 million, $2.3 million and $2.4 million for 2010, 2009 and 2008, 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. Expense associated with company contributions for 2010, 2009 and 2008 was $0.8 million for each year.

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. We are 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 2010, 2009 and 2008 we recognized expense of $3.5 million, $4.6 million and $4.4 million, respectively, for this plan.

22. TRANSACTIONS WITH RELATED PARTIES

As of February 16, 2011, members of the Darden family and entities controlled by them beneficially own approximately 32% of our outstanding common stock. Thomas Darden, Glenn Darden and Anne Darden Self are officers and directors of Quicksilver.

We paid $0.6 million in 2010, $0.7 million in 2009 and $1.9 million in 2008 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 a building located 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 $0.1 million in both 2010 and 2009 and $14,000 during 2008. Annual lease payments on the purchased building prior to its acquisition had been $1.1 million.

During 2010, 2009 and 2008, we paid $0.8 million, $0.2 million and $0.9 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 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 2010 or 2008.

Payments received in 2010, 2009 and 2008 from Mercury for sublease rentals, employee insurance coverage and administrative services were $0.3 million for each year.

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 $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.

An entity affiliated with Mercury received a $1.4 million commission from the lessor in connection with office space leased as of August 2010.

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)		
2010 (1)(2)				
Operating revenue	$ 222,158	$ 228,570	$ 237,700	$ 239,903
Operating income	75,845	108,867	65,092	538,181
Net income	10,600	90,744	26,569	316,880
Net income attributable to Quicksilver	8,188	86,803	21,803	318,275
Basic net earnings per share	$ 0.05	$ 0.51	$ 0.13	$ 1.87
Diluted net earnings per share	0.05	0.49	0.13	1.77
2009 (3)(4)(5)				
Operating revenue	$ 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

(1) Operating income for the third quarter of 2010 includes a charge of $28.6 for impairment of the HDCS to net realizable value.

(2) Operating income for the fourth quarter of 2010 includes a gain on sale of $473.2 million for the sale of all of our interests in KGS and a charge of $19.4 million for the impairment of our Canadian oil and gas properties.

(3) 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 income attributable to our proportionate ownership of BBEP and a charge of $102.1 million for impairment of the related investment, respectively.

(4) 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 income attributable to our proportionate ownership of BBEP.

(5) 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 loss attributable to our proportionate ownership of BBEP.

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

Proved oil and gas reserves estimates for our properties in the U.S. 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 2010 and 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 reserve reports used end-of-year prices adjusted for local differentials and applicable contract prices which conformed to the SEC guidelines 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, 2010 were as follows:

	Natural Gas (MMcf)			NGL (MBbl)			Oil (MBbl)		
	U.S.	Canada	Total	U.S.	Canada	Total	U.S.	Canada	Total
December 31, 2007	662,408	328,381	990,789	90,055	10	90,065	3,075	–	3,075
Revisions [4]	(171,009)	4,923	(166,086)	(25,596)	–	(25,596)	(106)	–	(106)
Extensions and discoveries [3]	560,205	22,363	582,568	31,662	–	31,662	428	–	428
Purchases in place [1]	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 [4]	(28,833)	(67,207)	(96,040)	(4,178)	7	(4,171)	205	1	206
Extensions and discoveries [3]	460,214	12,153	472,367	15,487	–	15,487	165	–	165
Purchases in place	314	–	314	–	–	–	–	–	–
Sales in place [2]	(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
Revisions [4]	13,389	(1,224)	12,165	4,845	2	4,847	606	–	606
Extensions and discoveries [3]	323,713	17,309	341,022	13,695	–	13,695	146	–	146
Purchases in place [1]	124,996	22,005	147,001	–	–	–	–	–	–
Production	(76,409)	(25,255)	(101,664)	(4,357)	(3)	(4,360)	(303)	–	(303)
December 31, 2010	1,941,723	265,888	2,207,611	112,444	12	112,456	3,308	–	3,308
Proved developed reserves									
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
December 31, 2010	1,312,777	242,941	1,555,718	64,908	12	64,920	2,775	–	2,775
Proved undeveloped reserves									
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
December 31, 2010	628,946	22,947	651,893	47,536	–	47,536	533	–	533

(1) Purchases of U.S. reserves in place during 2010 and 2008 relate principally to the acquisition of additional working interest in our company-operated Lake Arlington Project and the Alliance Transaction, respectively. These transactions are more fully described in Note 3 to our consolidated financial statements. The 2010 purchase of Canadian reserves in place relates to the acquisition of additional working interests in a company-operated field located in the Horseshoe Canyon.

(2) 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.

(3) 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:

- 2010 are 100% attributable to the Barnett Shale (of which 40% were proved developed);
- 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

Canadian extensions and discoveries for:

- 2010 are 69% attributable to Horn River Basin and 31% are attributable to Horseshoe Canyon;
- 2009 are 53% attributable to Horn River Basin and 47% are attributable to Horseshoe Canyon; and,
- 2008 are 100% attributable to Horseshoe Canyon.

(4) Revisions for each period presented reflect upward (downward) changes in previous estimates attributable to changes in operating and development costs, new information gained primarily from development drilling activity and production history and changes to development plans. Revisions

include (73,096) MMcfe, 132,846 MMcfe and (166,198) MMcfe for such matters in 2010, 2009 and 2008, respectively. Revisions also include 117,975 MMcfe, (251,676) MMcfe and (154,100) MMcfe for changes in sales price in 2010, 2009 and 2008.

The carrying value of our oil and gas assets as of December 31, 2010, 2009 and 2008 were as follows:

	U.S.	Canada	Consolidated
		(In thousands)	
2010			
Proved properties	$ 3,965,585	$ 839,576	$ 4,805,161
Unevaluated properties	153,880	160,663	314,543
Accumulated DD&A	(1,796,164)	(478,621)	(2,274,785)
Net capitalized costs	$ 2,323,301	$ 521,618	$ 2,844,919
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

Our consolidated capital costs incurred for acquisition, exploration and development activities during each of the three years ended December 31, 2010, were as follows:

	U.S.	Canada	Consolidated
		(In thousands)	
2010			
Proved acreage	$ 125,647	$ 19,271	$ 144,918
Unproved acreage	44,271	827	45,098
Development costs	378,056	14,182	392,238
Exploration costs	9,385	57,896	67,281
Total	$ 557,359	$ 92,176	$ 649,535
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

Consolidated results of operations from our producing activities for each of the three years ended December 31, 2010, are set forth below:

	U.S.	Canada	Consolidated
		(In thousands)	
2010			
Natural gas, NGL and oil revenue	$ 732,456	$ 123,893	$ 856,349
Operating expense	168,164	44,836	213,000
Depletion, depreciation and accretion	125,243	38,825	164,068
Impairment expense	–	19,386	19,386
	439,049	20,846	459,895
Income tax expense	153,667	6,045	159,712
Results from producing activities	$ 285,382	$ 14,801	$ 300,183
2009			
Natural gas, NGL and oil revenue	$ 608,013	$ 188,685	$ 796,698
Operating expense	112,935	38,661	151,596
Depletion, depreciation and accretion	127,888	33,783	161,671
Impairment expense	786,867	192,673	979,540
	(419,677)	(76,432)	(496,109)
Income tax benefit	(146,887)	(22,165)	(169,052)
Results from producing activities	$ (272,790)	$ (54,267)	$ (327,057)

	U.S.	Canada	Consolidated
		(In thousands)	
2008			
Natural gas, NGL and oil revenue	$ 597,889	$ 182,899	$ 780,788
Operating expense	114,374	38,662	153,036
Depletion, depreciation and accretion	120,845	40,337	161,182
Impairment expense	624,315	-	624,315
	(261,645)	103,900	(157,745)
Income tax expense (benefit)	(91,576)	30,131	(61,445)
Results from producing activities	$ (170,069)	$ 73,769	$ (96,300)

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 2010 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,		
	2010	2009	2008 [(1)]
Natural gas – Henry Hub	$ 4.38	$ 3.87	$ 5.71
Natural gas – AECO	4.08	3.76	5.44
NGL – Mont Belvieu, Texas	37.56	24.94	21.65
Oil – WTI Cushing	79.43	61.18	44.60

(1) The prices used for 2008 proved reserve estimates were year-end spot prices, which were previously required by the SEC guidelines then in effect.

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 at December 31, 2010, 2009 and 2008 was as follows:

	U.S.	Canada	Total
		(In thousands)	
December 31, 2010			
Future revenue	$ 12,057,094	$ 1,047,106	$ 13,104,200
Future production costs	(5,636,375)	(458,187)	(6,094,562)
Future development costs	(1,253,546)	(93,668)	(1,347,214)
Future income taxes	(1,254,255)	(62,370)	(1,316,625)
Future net cash flows	3,912,918	432,881	4,345,799
10% discount	(2,377,166)	(182,255)	(2,559,421)
Standardized measure of discounted future cash flows relating to proved reserves	$ 1,535,752	$ 250,626	$ 1,786,378
December 31, 2009			
Future revenue	$ 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 revenue	$ 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

The primary changes in the Standardized Measure for 2010, 2009 and 2008 were as follows:

	Years Ended December 31,		
	2010	2009	2008
		(In thousands)	
Sales of oil and gas net of production costs	$ (643,349)	$ (645,102)	$ (628,333)
Net changes in price and production cost	1,080,136	(715,484)	(2,368,940)
Extensions and discoveries	274,255	561,544	1,630,418
Development costs incurred	208,613	205,781	373,124
Changes in estimated future development costs	(341,612)	81,754	(413,097)
Purchase and sale of reserves, net	103,865	(144,279)	722,662
Revision of estimates	182,772	(248,681)	(618,527)
Accretion of discount	124,644	192,325	324,064
Net change in income taxes	(392,275)	196,691	509,854
Timing and other differences	6,650	(96,132)	93,834
Net increase (decrease)	$ 603,699	$ (611,583)	$ (374,941)

Quicksilver's Share of BBEP Reserves

The following disclosures required under GAAP represent our share of BBEP's reserves and BBEP's oil and gas operations, which are all located in the U.S. Note 7 in our consolidated financial statements contains 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 following provides information regarding ownership percentages utilized to apply toward BBEP's gross reported amounts, as applicable:

	2010	2009	2008
Ownership in BBEP at December 31,	29.44%	40.45%	40.56%
Annualized weighted average ownership of BBEP	34.62%	40.45%	40.56%

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

	For the Years Ended December 31,								
	2010			2009			2008		
	Total (Mboe)	Gas (MMcf)	Oil (MBbl)	Total (Mboe)	Gas (MMcf)	Oil (MBbl)	Total (Mboe)	Gas (MMcf)	Oil (MBbl)
Beginning balance	45,027	175,869	15,715	42,038	189,176	10,509	45,314	160,864	18,503
Revision of previous estimates	4,438	14,371	2,043	6,191	(4,203)	6,891	(12,903)	(6,591)	(11,805)
Purchase of reserves in place [1]	515	2,943	24	–	–	–	12,389	43,982	5,060
Sale of reserves in place [1]	(12,652)	(49,363)	(4,424)	(566)	(543)	(476)	–	–	–
Production	(2,319)	(7,357)	(1,093)	(2,636)	(8,561)	(1,209)	(2,762)	(9,079)	(1,249)
Ending balance	35,009	136,463	12,265	45,027	175,869	15,715	42,038	189,176	10,509
Proved developed reserves [2]									
Beginning balance	40,847	161,491	13,931	38,791	175,933	9,469	40,877	145,696	16,595
Ending balance	31,881	122,887	11,399	40,847	161,491	13,931	38,791	175,933	9,469
Proved undeveloped reserves [2][3]									
Beginning balance	4,180	14,378	1,784	3,247	13,243	1,040	4,437	15,168	1,908
Ending balance	3,128	13,576	866	4,180	14,378	1,784	3,247	13,243	1,040

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

	Years Ended December 31,		
	2010	2009	2008 [4]
Representative prices:			
Natural gas – Henry Hub	$ 4.38	$ 3.87	$ 5.71
Oil – WTI Cushing	79.40	61.18	44.60

(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) During 2010, capital expenditures of $11.3 million were incurred and 16 wells drilled to convert 922 MMcf of natural gas and 959 MBbl of oil from proved undeveloped to proved developed. During 2009, capital expenditures of $2.3 million were incurred and 11 wells drilled to convert 196 MMcf of natural gas and 230 MBbl of oil from proved undeveloped to proved developed.

(3) As of December 31, 2010 and 2009, no material proved undeveloped reserves have remained undeveloped for more than five years.

(4) The prices used for 2008 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, 2010 and 2009.

	At December 31, 2010	At December 31, 2009
	(In thousands)	
Proved properties and related producing assets	$ 551,573	$ 698,541
Pipeline and processing facilities	43,171	55,243
Unproved properties	33,291	79,166
Accumulated depreciation, depletion and amortization	(122,295)	(130,204)
Net capitalized costs	$ 505,740	$ 702,746

The following table summarizes our share of the capital costs incurred by BBEP during the three years ended December 31, 2010:

	2010	2009	2008
		(In thousands)	
Proved properties	$ 580	$ –	$ –
Unproved properties	996	–	–
Development costs	22,487	11,598	52,524
Asset retirement costs	3,504	1,975	553
Total	$ 27,567	$ 13,573	$ 53,077

The following table summarizes our share of BBEP's results of operations from its producing activities for each of the three years ended December 31, 2010:

	2010	2009	2008
		(In thousands)	
Oil, natural gas and NGL sales	$ 110,003	$ 103,126	$ 189,560
Gain (loss) on commodity derivative instruments	12,156	(20,808)	134,694
Operating costs	(49,343)	(56,029)	(65,706)
Depreciation, depletion & amortization	(34,684)	(42,194)	(72,460)
Income tax (expense) benefit	71	618	(786)
Results from producing activities	$ 38,203	$ (15,287)	$ 185,302

The following table summarizes our share of BBEP's Standardized Measure at December 31, 2010, 2009 and 2008:

	At December 31, 2010	2009	2008
		(In thousands)	
Future revenues	$ 1,500,867	$ 1,552,493	$ 1,429,072
Future development costs	(73,954)	(79,983)	(86,369)
Future production costs	(770,940)	(850,917)	(747,884)
Future net cash flows	655,973	621,593	594,819
10% discount	(342,435)	(314,290)	(354,610)
Standardized measure of discounted future cash flows relating to proved reserves	$ 313,538	$ 307,303	$ 240,209

The following table summarizes our share of the primary changes in BBEP's Standardized Measure for 2010, 2009 and 2008:

	At December 31,		
	2010	2009	2008
		(In thousands)	
Beginning balance	$ 307,303	$ 240,209	$ 609,120
Sales, net of production costs	(51,587)	(47,097)	(123,854)
Net changes in sales and transfer prices, net of production expense	90,185	88,093	(529,993)
Previously estimated development costs incurred	14,053	11,748	23,400
Changes in estimated future development costs	(30,975)	(14,969)	(39,773)
Purchase of reserves in place [1]	493	–	166,538
Sale of reserves in place [1]	(83,651)	(2,231)	–
Revision of quantity estimates and timing of production	45,353	7,590	57,205
Accretion of discount	22,365	23,960	77,566
Ending balance	$ 313,539	$ 307,303	$ 240,209

(1) Amounts are included as needed to reconcile our portion of beginning value to ending value that result from changes in our 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, 2010.

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, 2010.

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, 2010, 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, 2010, our internal control over financial reporting was effective.

The effectiveness of our internal control over financial reporting as of December 31, 2010, 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, 2010, that has materially affected, or is reasonably likely to materially 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, 2010, 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, 2010, 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, 2010 of the Company and our report dated March 11, 2011 an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP

Fort Worth, Texas
March 11, 2011

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 18, 2011 annual meeting of stockholders ("2011 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 2011 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 2011 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 2011 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 2011 Proxy Statement is incorporated herein by reference.

ITEM 11. Executive Compensation

The information set forth under "Executive Compensation," "Corporate Governance Matters - Compensation Committee Interlocks and Insider Participation," "Corporate Governance Matters - Director Compensation for 2010" and "Certain Relationships and Related Transactions" in our 2011 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 2011 Proxy Statement 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 2011 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 2011 Proxy Statement is incorporated herein by reference.

Information regarding our directors' independence set forth under "Corporate Governance Matters - Independent Directors" in the 2011 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 2011 Proxy Statement is incorporated herein by reference.

PART IV

ITEM 15.

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, our equity method investment, are being filed in accordance with SEC Rule 3-09 of Regulation S-X.

The management of BBEP is solely responsible for the form and content of the BBEP financial statements. We have no responsibility for the form or content of the BBEP financial statements since we do not control BBEP and are not involved in the management of BBEP. In addition, the consents of Schlumberger Data and Consulting Services, Netherland, Sewell & Associates and PricewaterhouseCoopers LLP are filed as exhibits under Item 15 of 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.

Exhibits

**2.1	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)
**2.2	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)
**2.3	Purchase Agreement, dated as of July 22, 2010, among First Reserve Crestwood Holdings LLC, Cowtown Gas Processing L.P., Cowtown Pipeline L.P. and Quicksilver Resources Inc. (filed as Exhibit 2.1 to the Company's Form 8-K filed on July 23, 2010 and included herein by reference)
**2.4	Purchase Agreement Amendment No. 1, dated as of September 17, 2010, among First Reserve Crestwood Holdings LLC, Cowtown Gas Processing L.P., Cowtown Pipeline L.P. and Quicksilver Resources Inc. (filed as Exhibit 2.2 to the Company's Form 10-Q filed on November 8, 2010 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)
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) (filed as Exhibit 4.5 to the Company's Form 10-K filed on March 15, 2010 and included herein by reference)
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) (filed as Exhibit 4.7 to the Company's Form 10-K filed on March 15, 2010 and included herein by reference)

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)
4.13	Amendment, dated as of February 23, 2011, to the Amended and Restated Rights Agreement between Quicksilver Resources Inc. and Mellon Investor Services LLC, as rights agent (filed as Exhibit 4.1 to the Company's Form 8-K filed February 23, 2011 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 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)
+ 10.3	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)
+ 10.4	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)
+ 10.5	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)
+ 10.6	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)
+ 10.7	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)
+ 10.8	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)
+ 10.9	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)
+ 10.10	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)

+ 10.11	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)
+ 10.12	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)
+ 10.13	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)
+ 10.14	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)
+ 10.15	Quicksilver Resources Inc. Amended and Restated 2009 Executive Bonus Plan (filed as Exhibit 10.22 to the Company's Form 10-K filed on March 15, 2010 and included herein by reference)
+ 10.16	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)
+ 10.17	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)
+ 10.18	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)
+ 10.19	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)
+ 10.20	Form of Director and Officer Indemnification Agreement (filed as Exhibit 10.2 to the Company's Form 10-Q filed on November 8, 2010 and included herein by reference)
10.21	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)
10.22	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)
10.23	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 (filed as Exhibit 10.30 to the Company's Form 10-K filed on March 15, 2010 and included herein by reference)
10.24	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 (filed as Exhibit 10.31 to the Company's Form 10-K filed on March 15, 2010 and included herein by reference)
10.25	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 (filed as Exhibit 10.32 to the Company's Form 10-K filed on March 15, 2010 and included herein by reference)
10.26	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)

10.27	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)
10.28	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 (filed as Exhibit 10.35 to the Company's Form 10-K filed on March 15, 2010 and included herein by reference)
10.29	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 (filed as Exhibit 10.36 to the Company's Form 10-K filed on March 15, 2010 and included herein by reference)
10.30	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)
10.31	Ninth Amendment to the Combined Credit Agreements, dated as of September 17, 2010, 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 10-Q filed on November 8, 2010 and included herein by reference)
10.32	Tenth Amendment to the Combined Credit Agreements, dated as of December 21, 2010, 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 on December 22, 2010 and included herein by reference)
10.33	Registration Rights Agreement, dated as of November 1, 2007, between Quicksilver Resources Inc. and BreitBurn Energy Partners L.P. (filed as Exhibit 10.1 to the Company's Form 8-K filed November 7, 2007 and included herein by reference)
10.34	First Amendment to Registration Rights Agreement, dated as of April 5, 2010, between Quicksilver Resources Inc. and BreitBurn Energy Partners L.P. (filed as Exhibit 4.1 to BreitBurn Energy Partners L.P.'s Form 8-K, File No. 001-33055, filed April 9, 2010 and included herein by reference)
10.35	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)
10.36	Asset Purchase Agreement, dated May 11, 2010, between Marshall R. Young Oil Co., as seller, and Quicksilver Resources Inc., as buyer (filed as Exhibit 10.1 to the Company's Form 8-K filed May 12, 2010 and included herein by reference)
10.37	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)
10.38	Confidentiality Agreement, dated October 24, 2010, between Quicksilver Resources Inc. and Quicksilver Energy L.P. (filed as Exhibit 10.1 to the Company's Form 8-K filed October 25, 2010 and included herein by reference)
10.39	Limited Waiver, dated as of February 23, 2011, between Quicksilver Resources Inc. and Quicksilver Energy L.P. (filed as Exhibit 10.1 to the Company's Form 8-K filed February 23, 2011 and included herein by reference)
10.40	Confidentiality Agreement, dated October 26, 2010, between Quicksilver Resources Inc. and SPO Partners II, L.P. (filed as Exhibit 10.1 to the Company's Form 8-K filed October 26, 2010 and included herein by reference)
10.41	Limited Waiver, dated as of February 23, 2011, between Quicksilver Resources Inc. and SPO Partners II, L.P. (filed as Exhibit 10.2 to the Company's Form 8-K filed February 23, 2011 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
* 101.INS	XBRL Instance Document
* 101.SCH	XBRL Taxonomy Extension Schema Linkbase Document
* 101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
* 101.LAB	XBRL Taxonomy Extension Labels Linkbase Document
* 101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
* 101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

* 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.

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

Dated: March 11, 2011

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 11, 2011
/s/ Glenn Darden Glenn Darden	President and Chief Executive Officer (Principal Executive Officer); Director	March 11, 2011
/s/ Philip Cook Philip Cook	Senior Vice President - Chief Financial Officer (Principal Financial Officer)	March 11, 2011
/s/ John C. Regan John C. Regan	Vice President, Controller and Chief Accounting Officer (Principal Accounting Officer)	March 11, 2011
/s/ Anne Darden Self Anne Darden Self	Director	March 11, 2011
/s/ W. Byron Dunn W. Byron Dunn	Director	March 11, 2011
/s/ Steven M. Morris Steven M. Morris	Director	March 11, 2011
/s/ W. Yandell Rogers, III W. Yandell Rogers, III	Director	March 11, 2011
/s/ Mark J. Warner Mark J. Warner	Director	March 11, 2011

QUICKSILVER RESOURCES INC.
2010 Finding, Development and Acquisition Cost
(Unaudited)

The following schedule reflects a reconciliation of 2010 "Finding, Development and Acquisition Cost" (FD&A) to the information required by Financial Accounting Standards Codification ("FASC") Topic 932 – Extractive Activities – Oil & Gas. FD&A cost is calculated by dividing (x) exploration, development, exploitation and acquisition capital expenditures for the period, plus asset retirement obligation additions and unevaluated capital expenditures as of the beginning of the period, less unevaluated capital expenditures as of the end of the period, by (y) reserve additions for the period, including acquired reserves.

2010 FD&A Cost – Dollars in millions, reserves in billions of cubic feet of natural gas equivalent

	Total Proved Reserves	Proved Developed Reserves
Total exploration, development, exploitation and acquisition capital expenditures	$ 649.5	$ 649.5
Asset retirement obligation additions	3.9	3.9
Adjustments:		
Unevaluated costs as of December 31, 2009	458.0	458.0
Unevaluated costs as of December 31, 2010	(314.5)	(314.5)
Adjusted capital expenditures related to reserve additions	$ 796.9	$ 796.9
Reserve extensions, discoveries, revisions and acquisitions (Bcfe)	616.0	443.2
Finding, development & acquisition cost ($/Mcfe)	$ 1.29	$ 1.80

Management believes that providing a measure of FD&A cost is useful to assist in an evaluation of Quicksilver's costs, on a per thousand cubic feet of natural gas equivalent (Mcfe) 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, FD&A cost does not necessarily reflect precisely the cost associated with particular reserves. For example, exploration costs may be recorded in periods prior to the period in which related increases in reserves are recorded and development costs may be recorded in periods subsequent to the period 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 FD&A costs will not differ materially from those set forth above.

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

Quicksilver Resources Inc.
Calculation of 2010 Production Replacement Ratio

The production replacement ratio is calculated by dividing the sum of reserve additions from all sources (extensions, discoveries, revisions and acquisitions) 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 & revisions	468,951
Acquisitions	147,001
Total additions	615,952
Production	129,642
Production replacement	475%

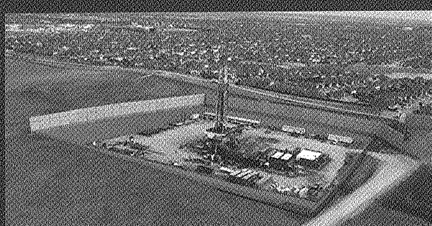
Quicksilver Resources Inc.
Calculation of Total Debt per Proved Reserve
As of December 31, 2010

Debt *($ in thousands)*	
Current portion of long-term debt	$ 143,478
Long-term debt	1,746,716
Total debt	$1,890,194
Total reserves *(MMcfe)*	2,902,195
Total debt per Mcfe	$ 0.65

CORPORATE INFORMATION

DIRECTORS

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



CORPORATE OFFICERS

Thomas F. Darden
Chairman of the Board
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
Stan G. Page
Senior Vice President – U.S. Operations
C. Clay Blum
Vice President – Land
Richard C. Buterbaugh
Vice President – Investor Relations & Corporate Planning
John Callanan
Vice President – Geology
Joseph Farley
Vice President – Rocky Mountains & New Ventures Operations
John E. Hinton
Vice President – Finance
Vanessa G. LaGatta
Vice President – Treasurer
Chris M. Mundy
Vice President – Engineering
John C. Regan
Vice President, Controller & Chief Accounting Officer
Clifford C. Rupnow
Vice President – Midstream Development
Anne D. Self
Vice President – Human Resources

All information as of March 1, 2011

HEADQUARTERS

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Fort Worth, Texas 76102
PHONE: 817-665-5000
FAX: 817-665-5004
quicksilver@qrinc.com
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MAJOR SUBSIDIARY

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

J. David Rushford
Senior Vice President and Chief Operating Officer of Quicksilver Resources Canada Inc.

REGISTRAR AND TRANSFER AGENT

BNY Mellon
480 Washington Blvd.
Jersey City, New Jersey 07310-1900
PHONE: 866-637-5420
www.bnymellon.com/shareowner/equityaccess

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 18, 2011
The Fort Worth Club
306 West 7th Street
Fort Worth, Texas 76102

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

QUICKSILVER
RESOURCES

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817.665.5000
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NYSE: KWK