Black Raven Energy, Inc.
Form 10-K
April 15, 2011
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2010

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

For the transition period from to

Commission file number: 001-32471

BLACK RAVEN ENERGY, INC.

(Exact Name of Registrant as Specified in Its Charter)

Nevada	**20-0563497**
(State or Other Jurisdiction of	(I.R.S. Employer Identification No.)

Incorporation or Organization)

1331 Seventeenth Street, Suite 350 **Denver, Colorado**	**80202**
(Address of Principal Executive Offices)	(Zip Code)

Registrant s Telephone Number, including area code: **(303) 308-1330**

Securities registered pursuant to Section 12(b) of the Act: **None.**

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 o No x

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

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 x No o

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) 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. o

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

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

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

There is no public market for the registrant s common stock. Therefore, the aggregate market value of the registrant s common stock held by non-affiliates as of June 30, 2010 was $0.

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes o No x

As of March 18, 2011, the registrant had 16,776,874 shares of common stock outstanding.

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Cautionary Note Regarding Forward-Looking Statements

We may from time-to-time make statements that are forward-looking, including statements contained in this Annual Report on Form 10-K and other filings with the Securities and Exchange Commission (the SEC) and in reports to our shareholders. Such statements may, for example, express expectations or projections about future actions that we may take or about developments beyond our control including changes in domestic or global economic conditions. These statements are made on the basis of our management s views and assumptions as of the time the statements are made and we undertake no obligation to update these statements. Our actual results may differ significantly from the results discussed in the forward-looking statements. General factors that might cause such differences include, but are not limited to:

- Changes in gas prices due to volatility of the market;
- Our ability to evaluate our future performance due to limited operating history;
- Our ability to replace reserves through development of existing properties in order to sustain production;
- Our ability to insure against liabilities associated with properties or obtain protection from sellers against them;
- Our dependence on a farm-out agreement and performance of the agreement by a third party;
- Our ability to acquire or transact business due to requirements of significant external capital changing our risk and property profile;
- Our ability to manage the risks inherent in operations of gas properties;
- Our exposure to guaranteed indebtedness of our subsidiaries and the covenants in the agreements governing that debt;
- Our ability to manage due to covenants limiting discretion of management in operating our business;

- Our ability to perform certain development operations depends on financing through equity or debt;
- Our ability to successfully integrate future acquisitions; and
- Our ability to attract and retain professional personnel.

For more information on these and other risk factors that may affect our business, refer to Item 1A Risk Factors included in this Annual Report.

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PART I

ITEM 1. BUSINESS.

Description of Business

Black Raven Energy, Inc. (Black Raven, the Company, us, our or we) , formerly known as PRB Energy, Inc. (PRB Energy) was original organized as a mid-stream energy company providing gathering and processing services to third party natural gas producers. During 2005 and 2006, we expanded our operations to include developing and producing natural gas properties along with providing management services as contract operator on jointly owned producing properties. In 2006, we also expanded our gathering services through acquisition of additional gathering systems in the Recluse, Wyoming area. By the end of 2007 and through 2008, our strategic focus was concentrated on recapitalization pursuits to generate the cash necessary to cover our debt service obligations and infuse additional capital required to realize our growth expectations. We filed for Chapter 11 bankruptcy on March 5, 2008 and emerged from bankruptcy on February 2, 2009.

During 2008, we also provided gas gathering and compression services for properties for third-party producers. As discussed below, during the pendency of our Chapter 11 bankruptcy from March 5, 2008 through February 2, 2009, we sold our Antelope Valley and South Kitty Pipeline, our GAP/Bonepile Gathering System and our Coal Bed Methane Fields, which were all gathering and processing assets.

Black Raven currently is focused on the development of low-risk shallow gas reserves in the Niobrara formation of the eastern D-J Basin. The Niobrara formation in this part of the D-J Basin is an unconventional tight gas play characterized by a chalk formation. The Company has approximately 178,000 net acres under lease in the play and operates 100% of its acreage position. The acreage is located in Sedgwick and Phillips counties in Colorado and in Perkins, Chase and Dundy counties in Nebraska. On July 23, 2010, the Company entered into a Farmout Agreement with Atlas Resources LLC (Atlas), a wholly-owned subsidiary of Atlas Energy, Inc, relating to natural gas drilling within an area of mutual interest in the Company s leased properties (the AMI). Since that time, our principal focus has been the execution of our obligations under that agreement. In addition,the Company is pursuing acquisitions of under-exploited oil and gas properties with potential upside.

We were initially incorporated in Nevada under the name PRB Transportation, Inc. in December 2003. On June 14, 2006, we changed our name to PRB Energy, Inc. On February 2, 2009, in connection with our emergence from bankruptcy, PRB Energy changed its corporate name to Black Raven Energy, Inc. Our corporate offices are located at 1331 Seventeenth Street, Suite 350, Denver, Colorado 80202, and our telephone number is (303)308-1330.

Emergence from Chapter 11 Bankruptcy

On January 16, 2009, the Bankruptcy Court entered an order confirming PRB Energy s and PRB Oil and Gas, Inc. s (PRB Oil), a wholly-owned subsidiary of PRB Energy, Modified Second Amended Joint Plan of Reorganization (the Plan).The,effective date of the Plan was February 2, 2009 (the Effective Date). Pursuant to the Plan, all of the issued and outstanding shares of PRB Energy s common stock were cancelled as of the Effective Date. The Plan further provided for the issuance of new common stock of Black Raven to certain claimants.

Pursuant to the terms of the Plan, the Company issued 1,419,339 shares of common stock, along with one warrant for each share at an exercise price of $2.50 per share, on a pro-rata basis to the holders of PRB Energy convertible notes. The Company issued an additional 74,959 shares of common stock, along with one warrant for each share at an exercise price of $2.50 per share, on a pro-rata basis to the other claimants related to accounts payable and accrued expenses and other current liabilities. The Company also issued 13.5 million shares of common stock to West Coast Opportunity Fund (WCOF), the principal pre-petition secured creditor.

After the effective date of the Plan, PRB Oil was merged into the Company. We deconsolidated PRB Gathering, Inc. (PRB Gathering), a wholly-owned subsidiary of PRB Energy during the fourth quarter of 2008. Effective November 1, 2008, control of the Recluse Gathering System was turned over to a receiver appointed by the State Court of Wyoming . Since that time, we have not been involved in the gathering and processing business. PRB Gathering was dismissed from Chapter 11 bankruptcy on February 17, 2010.

Farmout Agreement

On July 23, 2010, the Company entered into a Farmout Agreement (the Farmout Agreement) with Atlas relating to natural gas drilling within the AMI. Under the terms of the Farmout Agreement, Atlas agreed to drill six initial wells identified in the Farmout Agreement (the Initial Wells) and to complete certain initial projects, including 3D seismic shoots, upgrades of sales meter equipment, and the change-out of compressors and upgrade of a dehydrator at the Company s facility. The Company assigned to Atlas all of its rights, title and interests in the defined areas around the planned wellbores (the Drilling Units) for the Initial Wells.

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The Farmout Agreement also provides for Atlas, at its discretion, to drill additional wells in the AMI in accordance with work plans (each a Work Plan) approved by Atlas under the Farmout Agreement. The initial Work Plan approved by Atlas covering the period from July 23, 2010 to April 30, 2011 provides for Atlas, at its discretion, to drill 60 additional wells. For each six month period after April 30, 2011, Atlas must submit a proposal to the Company setting forth the numbers of wells that it proposes to drill for such six month period (the Drilling Proposal) and the Company must provide a Work Plan to be approved by Atlas outlining the development plan for the wells set forth in the Drilling Proposal. In the event that Atlas determines not to drill at least 60 wells in the course of any six month period, the Company has the right, during such six month period, to drill for its own account that number of wells equal to the difference between 60 wells and the number of wells agreed to be drilled by Atlas. Upon payment of a well-site fee, delivery of an executed authorization for expenditure (AFE) for such well by Atlas, and drilling and completion of the applicable well, the Company will assign all of its rights, title and interest in the Drilling Unit established for such well. The Farmout Agreement also provides for certain rights of the Company and Atlas with respect to the drilling of deep wells and for the payment of drilling and future 3D seismic costs by Atlas.

As of December 31, 2010, drilling of the Initial Wells had been completed, and Atlas had funded and drilled an additional 23 wells pursuant to the initial Work Plan. Since December 31, 2010, an additional 17 wells have been funded and drilled. The accounts payable balance at December 31, 2010 contains $813,000 of drilling costs related to the Farmout Agreement.

In consideration for the agreements made under the Farmout Agreement, Atlas paid the Company $1,000,000 upon execution of the Farmout Agreement. Such amount has been shown as a recovery of the cost of the Company s proved and unproved oil and gas properties, as applicable. In addition, Atlas agreed to pay the Company a $60,000 well-site fee for each well drilled by the Compnay for Atlas in the AMI, including the Initial Wells. As of December 31, 2010, the Company had received $1,740,000 as well site fees for 29 wells drilled. The well site fees received have been recorded as a recovery of the cost of the Company s oil and gas properties. The Company will recognize gains on any well-site fees received for future drilling under the Farmout Agreement at such time that all costs related to the oil and gas properties subject to the Farmout Agreement have been recovered.

The Company will also receive an undivided six percent of eight eighths (6% of 8/8ths) overriding royalty interest on substantially all of the oil and gas produced and sold that is attributable to the Drilling Units assigned to Atlas under the Farmout Agreement, subject to certain deductions.

The term of the Farmout Agreement is ten years, subject to earlier termination pursuant to the terms set forth therein.

On August 11, 2010, in connection with the Farmout Agreement and ongoing investment advisory services, the Company entered into an advisory fee agreement with a third party whereby the Company agreed to pay $10,000 per well for the first 220 wells that are funded and drilled by Atlas under the Farmout Agreement discussed above, up to a maximum fee of $2.2 million. As of December 31, 2010, Atlas had funded and drilled 29 wells, and the Company had paid an advisory fee of $290,000.

Competition

Our gas exploitation activities take place in a highly competitive and speculative business atmosphere. As an independent producer, we have little control over the price we receive for our natural gas. In seeking suitable oil and gas properties for development or acquisition, we compete with a number of other companies, including large oil and gas companies and other independent operators with greater financial resources. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties.

Revenues from two customers represented more than 90% of the Company s sales for the year ended December 31, 2010. We do not believe that the loss of any one customer would have a significant impact on our financial results because we believe there are other gas purchasers willing to take our production.

Government Regulation

Currently, the Company operates wells on state and fee lands. We believe that these wells and the facility operated by Black Raven are subject to and comply with all state regulations.

Federal, state and local authorities extensively regulate the energy industry. Legislation and regulations affecting the industry are under constant review for amendment or expansion, raising the possibility of changes that may affect, among other things, the pricing or marketing of gas production. Noncompliance with statutes and regulations may lead to substantial penalties and the overall regulatory burden on the industry increases the cost of doing business and, in turn, decreases profitability.

Governmental authorities regulate various aspects of gas drilling and production, including the drilling of wells (through permit and bonding requirements), the spacing of wells, the unitization or pooling of gas properties, environmental matters, safety standards,

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the sharing of markets, production limitations, plugging and abandonment and restoration.

The ongoing operations of the Company are subject to the Clean Water Act, the Clean Air Act, and other environmental regulations adopted by federal, state and local governmental authorities in jurisdictions where we are engaged in development or production operations. New laws or regulations, or changes to current requirements, could result in material costs or claims with respect to properties we own or have owned. We will continue to be subject to uncertainty associated with new regulatory interpretations and inconsistent interpretations between state and federal agencies. We could face significant liabilities to governmental authorities and third parties for discharges of oil, natural gas or other pollutants into the air, soil or water, and we could have to spend substantial amounts on investigations, litigation and remediation. Existing environmental laws or regulations, as currently interpreted or enforced, or as they may be interpreted, enforced or altered in the future, may have a material adverse effect on us.

We have reflected in our consolidated financial statements a reserve for future capital expenditures for remediation costs at the end of the life of the wells. Refer to Note 6 Asset Retirement Obligations to our consolidated financial statements in Item 8 of this Annual Report.

Employees

As of December 31, 2010, we had six full-time employees.

ITEM 1A. RISK FACTORS.

You should carefully consider the following risks and other information contained in this report. These risks could materially affect our business, results of operations or financial condition and adversely affect the value of our common stock. The risks and uncertainties described below are not the only risks facing us. If any of the following risks or uncertainties actually occurs, our business, financial condition and results of operations could be adversely affected.

Our auditors have expressed substantial doubt about our ability to continue as a going concern.

The accompanying consolidated financial statements have been prepared assuming the Company will continue as a going concern. As shown in the accompanying consolidated financial statements, the Company continues to experience net losses from its operations, reporting a net loss before reorganization items of $4.3 million for the year ended December 31, 2010. Cash and cash equivalents on hand and internally generated cash flows may not be sufficient to execute the Company s business plan. Future bank financings, asset sales, or other equity or debt financings will be required to fund the Company s debt service, working capital requirements, planned drilling, potential acquisitions and other capital expenditures. These conditions raise substantial doubt about the Company s ability to continue as a going concern.

Our consolidated financial statements do not include any adjustments that may result from the outcome of this uncertainty. If we cannot secure additional financing and continue to incur losses, we may be unable to maintain a level of liquidity necessary to continue operating our business and may be required to discontinue operations.

Risks Related to the Natural Gas Industry and Our Business

Natural gas prices are volatile and a decline in prices could hurt our financial condition, operating results and ability to grow.

Our revenues, operating results, profitability, future rate of growth and the carrying value of our gas properties depend heavily on the prices we receive from natural gas sales. Gas prices also affect our cash flows and borrowing base, as well as the amount and value of our gas reserves.

Historically, the markets for natural gas have been volatile and they are likely to continue to be volatile. Wide fluctuations in gas prices may result from relatively minor changes in the supply of and demand for gas, market uncertainty and other factors that are beyond our control, including:

- domestic supplies of natural gas;
- weather conditions in the United States and wherever our property interests are located or our gas is sold;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels;
- worldwide and domestic economic conditions;

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- actions by OPEC, the Organization of Petroleum Exporting Countries;
- political instability in major oil and gas producing regions;
- the level of consumer demand;
- changes in the overall supply and demand for oil and gas;
- the availability of transportation facilities;
- the ability of oil and gas companies to raise capital;
- the discovery rate of new oil and gas reserves;
- the cost of exploring for, producing and delivering oil and gas;
- the price of foreign imports of oil and gas; and
- governmental regulations and taxes, both domestic and foreign.

These factors and the volatility of gas markets make it very difficult to predict future gas price movements with any certainty. Declines in gas prices would reduce our revenues and could also reduce the amount of gas that we can produce economically and therefore could have a material adverse effect on us.

Our guarantee of certain indebtedness, and the covenants in the agreements governing that debt, could negatively impact our financial condition, results of operations and business prospects.

We guaranteed payment of the Amended and Restated Senior Secured Debenture (the Amended Debenture) and pledged substantially all of our assets as collateral. If we fail to comply with the restrictions in the agreements governing the Amended Debenture, an event of default could occur that would permit the lenders to foreclose on substantially all of our assets. Our ability to comply with these restrictions may be affected by events beyond our control, including prevailing economic and financial conditions. If we are required but unable to make the guaranteed payments under the Amended Debenture out of cash on hand or from internal cash flow, we could attempt to refinance the Amended Debenture, sell assets, or repay the Amended Debenture with the proceeds from an equity or debt offering. However, we may not be able to raise sufficient capital through the sale of assets or issuance of equity or debt to pay or refinance the amounts owed. Factors that will affect our ability to raise cash through a sale of assets or a debt or equity offering include financial market conditions and our market value and operating performance at the time of such offering or other financing. We may, therefore, not be able to successfully complete any such offering or sale of assets.

The Farmout Agreement has changed our business plan. We are relying on the ability of Atlas to fund our development plans, and the inability or failure of Atlas to fund our plans will hamper our growth.

The Farmout Agreement reduces our need to obtain funding. Our growth in gas sales under the Farmout Agreement will be from the 6% overriding royalty we receive from production of the wells drilled under the agreement. Our reliance on Atlas and the Farmout Agreement puts us at risk if Atlas is not able to meet its obligations or elects not to drill wells in the AMI.

Our development operations require substantial capital and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a disposition of properties and a decline in our natural gas reserves.

The energy industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for development, production and acquisition of oil and natural gas reserves. To date, we have financed capital expenditures primarily with proceeds from the issuance of debt and equity plus cash generated by operations. In addition to funding provided by Atlas under the Farmout Agreement, we intend to finance our future capital expenditures with cash flow from operations and from debt or equity capital. Our cash flow from operations and access to capital is subject to a number of variables, including:

- the success of the Farmout Agreement;
- our proved reserves;
- the level of natural gas we are able to produce from existing wells;
- the prices at which natural gas is sold; and
- our ability to acquire, locate and produce new reserves.

If our revenues decrease as a result of lower natural gas prices, operating difficulties, declines in reserves or for any other reason, then we may have limited ability to obtain the capital necessary to sustain our operations at current levels. We may, from time to time, need to seek additional financing. There can be no assurance as to the availability or terms of any additional financing.

If additional capital is needed, then we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If

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cash generated by operations is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations which in turn could lead to a possible disposition of properties and a decline in our reserves.

If we are not able to replace reserves, we will not be able to sustain production.

Our future operations depend on the Atlas Farmout Agreement and our ability to find, develop and acquire oil and gas reserves that are economically recoverable. Our properties produce gas at a declining rate over time. In order to become profitable, we must develop our properties or locate and acquire new oil and gas reserves to replace those being depleted by production. We may do this even during periods of low oil and gas prices. Competition for the acquisition of producing oil and gas properties is intense and many of our competitors have financial and other resources for acquisitions that are substantially greater than those available to us. Therefore, we may not be able to acquire oil and gas properties that contain economically recoverable reserves, or we may not be able to acquire such properties at prices acceptable to us. Without successful drilling or acquisition activities, our reserves, production and revenues will decline.

Our reserves and future net revenues may differ significantly from our estimates.

This Annual Report on Form 10-K contains estimates of our proved natural gas reserves. The estimates of reserves and future net revenues are not exact and are based on many variable and uncertain factors; therefore, the estimates may vary substantially from the actual amounts depending, in part, on the assumptions made and may be subject to adjustment either up or down in the future. The process of estimating natural gas reserves requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise. Actual future production, natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas reserves will vary from those estimated. Any significant variance could materially affect the estimated quantities and the value of our reserves. Our properties may also be susceptible to hydrocarbon drainage from production by other operators on adjacent properties. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing natural gas prices and other factors, many of which are beyond our control. The reserve data assumes that we will make significant capital expenditures to develop our reserves. Although estimates of these natural gas reserves and the costs associated with development of these reserves are prepared in accordance with SEC regulations, actual capital expenditures will likely vary from estimated capital expenditures, development may not occur as scheduled and actual results may not be as estimated.

Our prices, income and cash flows may be impacted adversely by new taxes.

The federal, state and local governments in which we operate impose taxes on the gas products we sell. There has been a significant amount of discussion by the United States Congress and presidential administrations concerning a variety of energy tax proposals. In addition, many states have raised state taxes on energy sources and additional increases may occur. We cannot predict whether any of these measures would have an adverse impact on natural gas prices, our income or cash flows.

The Amended Debenture contains various restrictions limiting the discretion of our management in operating our business.

The Amended Debenture contains various restrictions. In particular, these restrictions limit our ability, without the lenders approval, to, among other things:

- pay dividends on, redeem or repurchase our capital stock;
- make loans to others;
- incur additional indebtedness or issue preferred stock;
- create certain liens; and
- purchase or sell assets.

If we fail to comply with the restrictions of the Amended Debenture, an event of default may allow the creditors to foreclose on substantially all of our assets. Any such default or foreclosure could have a material adverse effect on us.

Continuing volatility in the financial and credit markets, and in oil and natural gas prices may affect our ability to obtain funding or to obtain funding on acceptable terms. These factors may hinder or prevent us from meeting our future capital needs and/or continuing to meet our obligations and conduct our business.

Global financial markets and economic conditions continue to be volatile, which has impacted the debt and equity capital markets. These issues, along with significant asset write-offs in the financial services sector, the re-pricing of credit risk and weak economic conditions, have made, and will likely continue to make, it difficult to obtain debt or equity capital funding.

Due to these factors, there can be no assurance that funding will be available to us, if needed, and to the extent required, on acceptable terms. If funding is not available as needed, or is available only on unfavorable terms, we may be unable to meet our

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obligations as they come due, enhance our existing business, complete acquisitions or otherwise take advantage of business opportunities, or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues, results of operations, financial position and cash flows.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Drilling and production activities are subject to numerous risks, including the risk that no commercially productive oil or natural gas will be found. The cost of drilling and completing wells is often uncertain, and oil and gas drilling and production activities may be shortened, delayed or canceled as a result of a variety of factors, many of which are beyond our control. These factors include:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental requirements;
- delays caused by regulatory approvals from state, local and other governmental authorities;
- shortages or delays in the availability of or increases in the cost of drilling rigs and the delivery of equipment;
- lack of availability of experienced drilling crews; and

- lack of pipeline availability or pipeline capacity.

The wells we drill may not be productive and we may not recover all or any portion of our investment in such wells. The seismic data and other technologies that we use do not allow us to know conclusively prior to drilling a well that oil or gas is present or may be produced economically. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Drilling activities can result in dry holes or wells that are productive but do not produce sufficient net revenues after operating and other costs to cover initial drilling costs.

Our future drilling activities may not be successful, or our overall drilling success rate or our drilling success rate for activity within a particular area may decline. Although we and our farmout partner Atlas have identified numerous potential drilling locations, we may not be able to economically produce oil or natural gas from them.

The occurrence of any or all of these risks could have a materially adverse effect on our business, financial condition and results of operations.

Our use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of natural gas which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. Therefore, 2-D and 3-D seismic data may not accurately identify the presence of natural gas.

Substantially all of our producing properties are located in the Rocky Mountain region, making us vulnerable to risks associated with operating in one major geographic area.

Our operations are focused on the Rocky Mountain region, and our producing properties are located in the states of Colorado and Nebraska. As a result, we may be disproportionately exposed to the impact of delays or interruptions of production from these areas caused by significant governmental regulation, transportation capacity constraints, curtailment of production or interruption of transportation of natural gas produced from the wells in these areas.

Our operations are subject to operational hazards and unforeseen interruptions for which we may be inadequately insured, resulting in losses to us.

Our operations, including gathering, processing, exploitation and production, are subject to operational hazards and unforeseen interruptions such as natural disasters, adverse weather, accidents, fires, explosions, hazardous materials releases, mechanical failures and other events beyond our control. These events might result in a loss of equipment or life, injury or extensive property damage, as well as an interruption in our operations. We may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. A significant liability for which we were not fully insured could adversely affect us.

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Our operations are subject to complex laws and regulations, including environmental regulations that may result in substantial costs and other risks.

Federal, state and local authorities extensively regulate the energy industry. Legislation and regulations affecting the industry are under constant review for amendment or expansion, raising the possibility of changes that may affect, among other things, the pricing or marketing of gas production. Noncompliance with statutes and regulations may lead to substantial penalties, and the overall regulatory burden on the industry increases the cost of doing business and, in turn, decreases profitability.

Governmental authorities regulate various aspects of gas drilling and production, including the drilling of wells (through permit and bonding requirements), the spacing of wells, the unitization or pooling of gas properties, environmental matters, safety standards, the sharing of markets, production limitations, plugging and abandonment and restoration.

Our operations are also subject to complex and constantly changing environmental laws and regulations adopted by federal, state and local governmental authorities in jurisdictions where we are engaged in development or production operations. New laws or regulations, or changes to current requirements, could result in material costs or claims with respect to properties we own or have owned. We will continue to be subject to uncertainty associated with new regulatory interpretations and inconsistent interpretations between state and federal agencies. We could face significant liabilities to governmental authorities and third parties for discharges of oil, natural gas or other pollutants into the air, soil or water, and we could have to spend substantial amounts on investigations, litigation and remediation. Existing environmental laws or regulations, as currently interpreted or enforced, or as they may be interpreted, enforced or altered in the future, may have a material adverse effect on us.

Future oil and gas price declines or unsuccessful development efforts may result in write-downs of our development and production asset carrying values, thereby reducing our assets and net worth.

We follow the successful efforts method of accounting for our oil and gas properties. All property acquisition costs and costs of development wells are capitalized when incurred, pending the determination of whether proved reserves have been discovered.

The capitalized costs of our oil and gas properties, on a field basis, cannot exceed the estimated future net cash flows of that field. If net capitalized costs exceed future net cash flows, we must write-down the costs of each such field to our estimate of fair market value. Accordingly, a significant decline in oil or gas prices or unsuccessful development efforts could cause a future write-down of capitalized costs, reducing our assets and net worth.

We review the carrying value of our properties quarterly based on prices in effect as of the end of each quarter. Once incurred, a write-down cannot be reversed at a later date even if prices increase.

Competition in our industry is intense and many of our competitors have greater financial and technical resources than we do.

We face intense competition from major oil companies, independent oil and gas exploration and production companies, financial buyers and institutional and individual investors who are actively seeking oil and gas properties in the Rocky Mountain region in which we operate and elsewhere. Many of our competitors have financial and technical resources along with equipment, expertise, labor and materials significantly exceeding those available to us. In addition, many properties are sold in a competitive bidding process in which our competitors may be able to pay more for development prospects and productive properties, or in which our competitors have technological information or expertise to evaluate and successfully bid for the properties that is not available to us. Shortages of equipment, labor or materials as a result of intense competition may result in increased costs or the inability to obtain those resources as needed. We, therefore, may not be successful in acquiring and developing profitable properties in the face of this competition.

Acquisitions or other transactions could require significant external capital and could change our risk and property profile.

In order to finance acquisitions of additional producing properties, we may need to alter or increase our capitalization substantially through the issuance of debt or equity securities or other means. These changes in capitalization may significantly affect our risk profile. Additionally, significant acquisitions or other transactions could change the character of our operations and business. The character of the new properties could be substantially different in operating or geological characteristics or geographic location than our existing properties. Furthermore, we may not be able to obtain external funding for future acquisitions or other transactions or to obtain external funding on terms acceptable to us.

Properties we acquire may not produce as projected, and we may be unable to identify liabilities associated with the properties or obtain protection from sellers against them.

Our business strategy includes an acquisition program. The successful acquisition of producing oil and gas properties requires assessments of many factors, which are inherently inexact and may be inaccurate, including the following:

- the amount of recoverable reserves;
- future oil and natural gas prices;
- estimates of operating costs;

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- estimates of future development costs;
- estimates of the costs and timing of plugging and abandonment; and
- potential environmental and other liabilities.

Our assessment will not reveal all existing or potential problems, and may not permit us to become familiar enough with the properties to fully assess their capabilities and deficiencies. In the course of our due diligence, we may not inspect every well or pipeline. Inspections may not reveal structural and environmental problems, such as pipeline corrosion or groundwater contamination, when they are made. We may not be able to obtain contractual indemnities from the seller for liabilities that it created. We may be required to assume the environmental and production risks associated with the properties.

We depend on our chief executive officer, our president and other officers for critical management decisions and industry contacts.

We have a small management team and have employment agreements with our chief executive officer, our president and other executive officers. We do not carry key person insurance on their lives. The loss of the services of our executive officers through incapacity or otherwise, could have a material adverse effect on our operations and would require us to seek and retain other qualified personnel.

Our ability to successfully recruit qualified managerial and field personnel having experience in oil and gas exploration, significantly impacts our operations.

In order to successfully implement and manage our business plan, we will depend upon, among other things, successfully recruiting qualified managerial and field personnel having experience in the oil and gas exploration business. Competition for qualified individuals is intense. We may not be able to find, attract and retain qualified personnel on acceptable terms. If we are unable to find, attract and retain qualified personnel with technical expertise, our business operations could suffer.

Our business could be adversely impacted if we have deficiencies in our disclosure controls and procedures or internal control over financial reporting.

In connection with our SEC reports, our management is required to provide a report on our internal controls over financial reporting including an assessment of the effectiveness of these controls to provide reasonable assurance a material misstatement did not occur in our financial statements. While our management continues to review the effectiveness of our disclosure controls and procedures and internal control over financial reporting, we cannot assure you that our disclosure controls and procedures or internal control over financial reporting will be effective in accomplishing all control objectives all of the time.

We have limited operating history since emerging from bankruptcy.

Since emerging from bankruptcy on February 2, 2009, we have not generated significant revenues from operations and we have limited resources. Any operating losses, together with risks associated with our ability to be competitive in the natural gas industry, may have a material adverse effect on our liquidity. An investor in our common stock must evaluate the risks, uncertainties, and difficulties encountered by a company that has emerged from Chapter 11 bankruptcy. There can be no assurance that we will generate sufficient revenues to maintain our business operations.

Risks Related to our Common Stock

We are a voluntary filer with the SEC and we may cease reporting at any time.

We are currently filing reports with the SEC but we may cease reporting at any time. In that event, the liquidity of our common stock would be severely diminished and our ability to continue our operations could be materially affected.

West Coast Opportunity Fund, LLC owns a significant percentage of our Company and can exercise significant influence over us.

As of our emergence from Chapter 11 bankruptcy on February 2, 2009, WCOF owned approximately 90% of the outstanding shares of our common stock. Through the purchase of additional shares in 2009 and the payment of accrued interest in our common stock in 2010, WCOF owned 91% of the outstanding shares of our common stock as of December 31, 2010. So long as WCOF controls a majority of our outstanding equity, WCOF will continue to have the ability to control any matters submitted for stockholder approval such as mergers, sales of all or substantially all of our assets, amendments to our articles of incorporation, and other corporate matters. This concentration of ownership by WCOF may discourage additional investors in the Company or prevent us from undergoing a change of control in the future that would otherwise be beneficial to shareholders.

No established trading market exists for the common stock we issued upon our emergence from bankruptcy, and if one develops, it may not be liquid.

No established trading market exists for the common stock we issued upon our emergence from bankruptcy, and there is no assurance that any active trading market will develop in the future. There is no assurance that any national securities exchange will

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approve our new common stock for listing as there is no assurance that we will satisfy the criteria for listing, or be approved for listing on such exchange. Absent an active public market for our common stock, an investment in our shares should be considered illiquid. There is no assurance that a sufficient market will develop in our stock, in which case it could be difficult for our stockholders to sell their shares. The market for our stock may be further impacted by our status as a voluntary filer with the SEC. Such status will restrict our common stock from trading on a securities exchange.

Trading of our stock may be restricted by the SEC s penny stock regulations, which may limit a stockholder s ability to buy and sell our common stock.

The SEC has adopted regulations which generally define penny stock to be any equity security that has a market price (as defined) less than $5.00 per share or an exercise price of less than $5.00 per share, subject to certain exceptions. Our securities may be covered by the penny stock rules, which impose additional sales practice requirements on broker-dealers that sell to persons other than established customers and accredited investors . The penny stock rules require a broker-dealer, prior to a transaction in a penny stock not otherwise exempt from the rules, to deliver a standardized risk disclosure document in a form prepared by the SEC, which provides information about penny stocks and the nature and level of risks in the penny stock market. The broker-dealer also must provide the customer with current bid and offer quotations for the penny stock, the compensation of the broker-dealer and its salesperson in the transaction and monthly account statements showing the market value of each penny stock held in the customer s account. The bid and offer quotations, and the broker-dealer and salesperson compensation information, must be given to the customer orally or in writing prior to effecting the transaction and must be given to the customer in writing before or with the customer s confirmation. In addition, the penny stock rules require that prior to a transaction in a penny stock not otherwise exempt from these rules, the broker-dealer must make a special written determination that the penny stock is a suitable investment for the purchaser and receive the purchaser s written agreement to the transaction. These disclosure requirements may have the effect of reducing the level of trading activity in the secondary market for the stock that is subject to these penny stock rules. Consequently, these penny stock rules may affect the ability of broker-dealers to trade our securities, which ultimately may affect the liquidity of our securities.

The FINRA sales practice requirements may also limit a stockholder s ability to buy and sell our stock.

In addition to the penny stock rules described above, Financial Industry Regulatory Authority (FINRA) has adopted rules that require that in recommending an investment to a customer, a broker-dealer must have reasonable grounds for believing that the investment is suitable for that customer. Prior to recommending speculative low priced securities to their non-institutional customers, broker-dealers must make reasonable efforts to obtain information about the customer s financial status, tax status, investment objectives and other information. Under interpretations of these rules, FINRA believes that there is a high probability that speculative low priced securities will not be suitable for at least some customers. The FINRA requirements make it more difficult for broker-dealers to recommend that their customers buy our common stock, which may limit your ability to buy and sell our stock and have an adverse effect on the market for our shares.

If a market develops for our common stock, our stock price and trading volume may be volatile, which could result in losses for our stockholders.

Even if a market for our common stock is established, the price of our common stock may be volatile. The equity trading markets have experienced and may experience periods of volatility, which could result in highly variable and unpredictable pricing of equity securities. The market price of our common stock could change in ways that may or may not be related to our business, our industry or our operating performance and financial condition. In addition, the trading volume in our common stock may fluctuate and cause significant price variations to occur. Some of the factors that could negatively affect our share price or result in fluctuations in the price or trading volume of our common stock include:

- actual or anticipated quarterly variations in our operating results;
- changes in expectations as to our future financial performance or changes in financial estimates, if any, of public market analysts;
- announcements relating to our business or the business of our competitors;
- conditions generally affecting the oil and natural gas industry, including economic or other conditions that affect the demand for oil and natural gas;
- the success of our operating strategy; and
- the operating and stock price performance of other comparable companies.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

Not applicable.

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ITEM 2. PROPERTIES.

Description of Properties

D-J Basin-Niobrara Formation

In December 2006, we purchased approximately 385,000 acres and 13 wells in eastern Colorado and western Nebraska, which were drilled to the Niobrara formation in the D-J Basin. The Niobrara formation in this part of the D-J Basin is an unconventional tight gas play characterized by a chalk formation. It is a high porosity/low permeability reservoir, roughly 40 feet thick with widespread structural biogenic gas deposits and extensive faulting. The Company has approximately 178,000 net acres under lease in the play and operates 100% of its acreage position. The acreage is located in Sedgwick and Phillips counties in Colorado and in Perkins, Chase and Dundy counties in Nebraska.

Modern methods used to evaluate the Niobrara in the eastern D-J Basin are predominately driven by geophysics. Typically, leads are generated by 2-D seismic or subsurface mapping. The delineated anomalies are subsequently shot with 3-D seismic mapping effectively identifying gas by amplitude.

In 2007, we drilled 12 wells to the Niobrara. Eleven wells intercepted a productive section of the Niobrara. During 2010, the Company completed three wells and conducted a workover of one well.

On July 23, 2010, the Company entered into the Farmout Agreement with Atlas. Under the terms of the Farmout Agreement, Atlas agreed to drill six Initial Wells and to complete certain initial projects, including 3D seismic shoots, upgrades of sales meter equipment, and the change-out of compressors and upgrade of a dehydrator at the Company s facility. The Company assigned to Atlas all of its rights, title and interests in the defined areas around the Drilling Units for the Initial Wells.

The Farmout Agreement also provides for Atlas, at its discretion, to drill additional wells in the AMI in a Work Plan approved by Atlas under the Farmout Agreement. The initial Work Plan approved by Atlas covering the period from July 23, 2010 to April 30, 2011 provides for Atlas, at its discretion, to drill 60 additional wells. Upon payment of a well-site fee and delivery of an executed authorization for expenditure for such well by Atlas, the Company will assign all of its rights, title and interest in the Drilling Units established for such well. The Farmout Agreement also provides for certain rights of the Company and Atlas with respect to the drilling of deep wells and for the payment of drilling and future 3D seismic costs.

As of December 31, 2010, drilling of the Initial Wells has been completed, and Atlas has funded and drilled an additional 23 wells pursuant to the initial Work Plan. Since December 31, 2010, an additional 17 wells have been funded and drilled.

In consideration for the agreements made under the Farmout Agreement, Atlas paid the Company $1,000,000 upon execution of the Farmout Agreement, and a $60,000 well-site fee for each well drilled for Atlas in the AMI, including the Initial Wells. As of December 31, 2010, the Company had received $1,740,000 as well site fees for 29 wells. All amounts received from Atlas in 2010 are shown as a recovery of the cost of the Company s oil and gas properties. The Company will recognize gains on any well-site fees received for future drilling under the Farmout Agreement at such time that all costs related to the oil and gas properties subject to the Farmout Agreement have been recovered.

The Company will also receive an undivided six percent of eight eighths (6% of 8/8ths) overriding royalty interest on substantially all of the oil and gas produced and sold that is attributable to the Drilling Units assigned to Atlas under the Farmout Agreement, subject to certain deductions.

The term of the Farmout Agreement is ten years, subject to earlier termination pursuant to the terms set forth therein.

Powder River Basin - CBM

In 2006, the Company obtained approximately a 9.0% non-operated working interest in the Homestead Draw CBM Field in Campbell County, Wyoming. This field produces from multiple coal beds. As of December 31, 2010, we continue to hold a minor working interest position in this property.

Recluse Gathering System

In 2006, we made three acquisitions that were combined into our Recluse Gathering System. The system included two compressor stations, with interconnects with two major transportation lines and 74.5 miles of steel pipelines. The Recluse Gathering System was formerly an asset of PRB Gathering, Inc. Effective November 1, 2008, control of the Recluse Gathering System was turned over to a receiver appointed by the State Court of Wyoming. PRB Gathering was dismissed from Chapter 11 Bankruptcy on February 17, 2010.

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Reserves

In December 2008, the SEC announced that it had approved revisions to oil and gas reporting requirements. A key revision to the rules pertains to commodity prices. The economic producibility of reserves and discounted cash flows are now based on a 12-month average commodity price as opposed to a year-end price in estimating reserves.

The revised SEC rules also provide for the use of new technology to estimate proved reserves. Additionally, the definition of proved oil and gas reserves was expanded to include non-traditional resources, which focuses on the marketable product rather than the method of extraction.

The Company s natural gas reserves at December 31, 2010 are set forth in the following table. All of the reserves are located within the continental United States.

Reserves Category	**Natural Gas Reserves MMcf**
Proved Developed	1,440
Proved Undeveloped	5,023
TOTAL PROVED	**6,463**

As of December 31, 2010 and December 31, 2009, 22.28% and 18.81% of the proved reserves were categorized as proved developed producing, respectively.

A third party reserve audit was prepared by MHA Petroleum Consultants, Inc. (MHA). MHA provides a wide array of reservoir evaluation services including reserve determinations, prospect evaluations and acquisition and divestiture of properties. MHA s typical professional has 20 years of oil and gas experience. The lead consultant overseeing the Company s reserve report was Leslie S. O Connor, the president of MHA. She has over 30 years working as a petroleum industry consultant. She holds a degree in geology from Northern Arizona University and attended Colorado School of Mines for graduate studies in petroleum engineering. MHA was incorporated in 1994. Due to the size of our Company, Black Raven relies on the reserve audit prepared by MHA for its reserve estimates. MHA s report to management, which summarized the scope of work preformed and its conclusions, has been included in this Annual Report as Exhibit 99.1.

- MHA was commissioned by the Company to complete a reserve audit subject to the new SEC regulations with an effective date of January 1, 2011.

- The Company s reserve base is located in Colorado.

• MHA completed an independent decline curve analysis on the Company s proved producing wells. This analysis is supplemented by experience in the area with the producing formations. Production volumes were provided to MHA. All production volumes could be independently verified through public sources.

• MHA completed an analysis of the proved non-producing and proved undeveloped reserves using 3D seismic interpretation, volumetric analyses, and local and regional analogies.

• Additional information provided to MHA included average first of month pricing for 2010 in order to comply with the new SEC regulations, working and revenue interests in each well or property, lease operating expenses, estimated capital costs, and estimated timing for development.

• MHA s reserve estimates were assigned on the basis of the SEC definitions, effective January 1, 2010.

• Management has reviewed the reserve report and agrees with the work performed by MHA.

Proved Undeveloped Reserves

As presented in the chart above, at year end 2010, Black Raven had 5,023 MMcf of proved undeveloped reserves. At year end 2009, Black Raven had 7,428 MMcf of proved undeveloped reserves. The decrease of 2,405 MMcf is the result of revisions to previous estimates and the conversion of our working and revenue interest to the 6% overriding royalty interest in the wells drilled under the Farmout Agreement. During 2010, the Company conducted no drilling operations in order to increase reserves for our own interests.

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Gas Sales

The following table summarizes the volumes sold and realized prices from our properties during the years ended December 31, 2010 and December 31, 2009 respectively. All items listed below are based on gas sales volume (Mcf). Therefore, these values are net numbers that remove fuel, lost and unaccounted for gas, and metering variances prior to the calculation.

	2010	2009
Net annual gas sales (Mcf) *(1)*	123,885	149,297
Average net daily gas sales (Mcf)	339	409
Average realized price of gas per Mcf sold	$ 3.79	$ 3.08
Lease operating expense per Mcf sold	$ 5.72	$ 3.33
Production taxes per Mcf sold	$ 0.32	$ 0.31
Transportation expense per Mcf sold	$ 1.06	$ 1.78

(1) Net gas sales represent that portion of gas sold that is owned by us and produced to our ownership interest.

Productive Wells

As of December 31, 2010 and December 31, 2009, we had working interests in 68 gross productive wells (31 wells net) and 63 gross productive wells (31 wells net), respectively. Productive wells are either producing or capable of producing although shut-in or de-watering. Gross wells represent the total number of wells in which we have a working interest. Net wells represent the number of gross wells multiplied by the percentages of the working interests owned by us. One or more completions in the same bore hole are counted as one well.

Drilling Activity

In 2010, the Company completed three wells previously drilled and conducted a workover of another well. During 2010 and 2009, the Company conducted no drilling operations other than on behalf of Atlas under the terms of the Farmout Agreement.

Acreage

The following table details the gross and net acres of developed and undeveloped properties in which we had working interests. As of December 31, 2010, our properties accounted for the following developed and undeveloped acres:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Wyoming	1,011	94	806	74	1,817	168
Colorado	960	960	100,188	92,421	101,148	93,381
Nebraska			97,153	84,078	97,153	84,078
Total	1,971	1,054	198,147	176,573	200,118	177,627

Developed refers to acreage with drilled and producing or drilled and shut-in wells. Undeveloped refers to acreage that has not been drilled Gross represents acres in which we have a working interest. Net represents our aggregate working interests in the gross acres. The acreage in Colorado and Nebraska is the Farmout Agreement AMI .

Office Facilities

We currently lease office space for our corporate headquarters at 1331 Seventeenth Street, Suite 350, Denver, Colorado 80202.

ITEM 3. LEGAL PROCEEDINGS.

On March 5, 2008, PRB Energy and its subsidiaries filed voluntary petitions for relief for each business entity under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the District of Colorado. On January 16, 2009, the Bankruptcy Court entered an order confirming PRB Energy s and PRB Oil s Modified Second Amended Joint Plan of Reorganization. On February 2, 2009, PRB Energy and PRB Oil emerged from bankruptcy and PRB Energy changed its name to Black Raven Energy, Inc. PRB Gathering, Inc. s Chapter 11 bankruptcy case was dismissed on February 17, 2010. See Item 1 Emergence from Chapter 11 Bankruptcy of this Annual Report.

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As of the date of filing of this Annual Report, we are not currently party to any material pending litigation or government proceedings.

ITEM 4. RESERVED.

PART II

ITEM 5. MARKET FOR REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

Common Stock

There is no established trading market for the Company s common stock, as it is not currently traded or quoted on a national securities exchange, the OTC Bulletin Board or the Pink Sheets.

As of December 31, 2010, there were approximately 301 record holders of our common stock.

Dividend Policy

We have never paid cash dividends on our common stock and we do not anticipate paying dividends in the foreseeable future. We expect that we will retain all available earnings generated by our operations for the development and growth of our business. In addition, under the terms of the Amended Debenture that was issued on February 2, 2009 in connection with our emergence from Chapter 11 bankruptcy, we are prohibited from declaring or paying cash dividends on our common stock during the period that the Amended Debenture is outstanding and unpaid. Payment of any future dividends will be at the discretion of our Board of Directors after taking into account many factors, including our operating results, financial condition, current and anticipated cash needs, plans for expansion and the Amended Debenture.

ITEM 6. SELECTED FINANCIAL DATA.

Not applicable.

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

This Management s Discussion and Analysis should be read in conjunction with the accompanying consolidated financial statements, which have been prepared assuming we will continue as a going concern. Management s plans concerning these matters are also described in Note 1 to the consolidated financial statements. The consolidated financial statements do not include any adjustments that might result from this uncertainty.

Overview

Black Raven is currently focused on the development of low-risk shallow gas reserves in the Niobrara formation of the eastern D-J Basin. The Niobrara formation in this part of the D-J Basin is an unconventional tight gas play characterized by a chalk formation. The Company has 178,000 net acres under lease in the play and operates 100% of its acreage position. The acreage is located in Sedgwick and Phillips counties in Colorado and in Perkins, Chase and Dundy counties in Nebraska.

On March 5, 2008, PRB Energy and its subsidiaries filed voluntary petitions for relief for each business entity under Chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court for the District of Colorado. PRB Energy continued to operate its business as a debtor-in-possession under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code.

On January 16, 2009, the Bankruptcy Court entered an order confirming PRB Energy s and PRB Oil s Modified Second Amended Joint Plan of Reorganization. On February 2, 2009, PRB Energy and PRB Oil emerged from bankruptcy and PRB Energy changed its name to Black Raven Energy, Inc. PRB Oil was subsequently merged into the Company. See Item 1 of this Annual Report for a summary of developments since our emergence from bankruptcy.

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On July 23, 2010, the Company entered into the Farmout Agreement with Atlas. Since that time, our principal focus has been the execution of our obligations under that agreement. As such, the principal source of cash flow for our operations will be from the well site fees from drilling wells under the Farmout Agreement. The principal source of increasing natural gas sales will be from the 6% overriding royalty interest we have in the wells under the Farmout Agreement. The well site fees received will be recorded as a recovery of the cost of the Company s oil and gas properties. The Company will recognize gains on any well-site fees received for future drilling under the Farmout Agreement at such time that all costs related to the oil and gas properties subject to the Farmout Agreement have been recovered.

Results of Operations for the Year Ended December 31, 2010

Summarized Results of Operations

		(in thousands)
Natural gas sales	$	469
Operating expenses		3,042
Operating loss		(2,573)
Other expense		(1,749)
Gain on reorganization		1,072
Other reorganization items		(17)
Net loss	$	(3,267)

The following financial data should be read in conjunction with, and are qualified by reference to, our consolidated financial statements and related notes thereto in Item 8 of this Annual Report. The financial statements have been prepared assuming the Company will continue as a going concern. See Note 3 of the Financial Statements for a complete discussion of the Company s reorganization.

Natural gas sales Our natural gas sales are determined by production from our existing properties and prices based on market conditions for natural gas. These market conditions, such as weather, pipeline capacity and natural gas storage, may have substantial effect on the revenues we generate.

Operating Expenses

Natural Gas Production Expense Natural gas lease production expense includes costs associated with operating the natural gas properties and production taxes. Such costs include labor related to pumper and direct field supervision, electricity, surface-use agreements, equipment rental, fuel, chemicals, road maintenance, permits, supplies and other relevant well costs incurred to extract the natural gas from the well. Production taxes are determined by the taxing authority. In 2010 and 2009, our production taxes were paid primarily to the State of Colorado. These taxes included ad valorem charged by the counties based on assessed valuation of the properties, and severance and conservation taxes charged by the state. A nominal amount was paid to the State ofWyoming in connection with our production within the Homestead Draw area.

Depreciation, Depletion, Amortization and Accretion Expense Depreciation expense relates to our compressor sites, pipelines and other gas gathering equipment, office furniture, office equipment and computers. Depletion expense relates to developed and undeveloped leaseholds, capitalized development costs and related equipment. Amortization expense relates to the customer contracts underlying the gas gathering systems. Accretion expense relates to the change in our asset retirement obligation liability due to the passage of time. Depreciation and amortization expenses are based on estimates of the related assets useful lives. Depletion expense is calculated using the unit-of-production method based on estimated proved or estimated proved developed reserves. Accretion expense is calculated using the effective interest method.

Exploration Expense Exploration expense includes the costs of drilling unsuccessful exploratory wells.

General and Administrative Expense General and administrative expense includes the costs associated with our corporate office, including personnel costs, professional fees, office rent and other office support costs.

Other Expense

Interest Expense Interest expense primarily includes interest incurred on the Amended Debentures payable to West Coast Opportunity Fund in the amount of $18.8 million.

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Asset Impairment Charge Assets are evaluated for impairment periodically throughout the year. In 2010, we did not incur any impairment expense.

Gain on Reorganization The Company recognized a gain on reorganization of $1 million upon the dismissal of PRB Gathering from bankruptcy in 2010.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

Natural gas sales increased to $469,000 in 2010 from $460,000 in 2009, an increase of approximately $9,000, or 2%. Natural gas price increases of an average $.71 per Mcf resulted in a $106,000 increase in revenue. Volumetric declines resulted in a $97,000 decline in revenue.

Selected Operating Expenses. The following table and the explanations that follow present information about our operating expenses for each of the years ended December 31, 2010 and 2009:

(in thousands)		**2010**		**2009**		**Increase (Decrease)**	**Change**
Natural gas production expense	$	776	$	616	$	160	26%
Depreciation, depletion, amortization and accretion	$	165	$	252	$	(87)	(35)%
General and administrative (including bankruptcy expenses)	$	2,106	$	2,126	$	(20)	(1)%
Interest expense	$	1,760	$	1,303	$	457	35%

The changes set forth in the preceding table primarily related to the following items:

Natural gas production expense. The increase of $160,000 or 26% was a result of the increase in operating costs primarily due to repairs and workover expenses incurred during 2010.

Depreciation, depletion, amortization and accretion. The decrease of $87,000 resulted mainly from the decrease in production volumes from 2009 to 2010.

General and administrative. The decrease of $20,000, or 1%, was a result of decreased legal and other professional services incurred during 2010 partially offset by increased personnel costs and general office-related expenses incurred in 2010.

Interest expense. Interest expense increased $457,000, or 35%, due to the increase in the interest rate on the Amended Debentures from 2.5% in 2009 to 10% in the fourth quarter of 2010 as required by the Plan. We recorded a $1.4 million discount on the Amended Debenture upon issuance. The discount on the Amended Debenture was amortized using the retrospective interest method and was fully amortized at December 31, 2010. The discount is included in the balance of the Amended Debenture at December 31, 2009. For the year ended December 31, 2010, the Company recorded $672,000 of interest expense related to the amortization of the discount on its Amended Debenture. The interest expense related to the amortization of the discount for the year ended December 31, 2009 was $743,000.

Financial Condition, Liquidity and Capital Resources

The accompanying audited consolidated financial statements for the year ended December 31, 2010 were prepared under the assumption that we will continue to operate as a going concern, which contemplates the realization of assets and the liquidation of liabilities in the normal course of business.

Working Capital At December 31, 2010, cash and cash equivalents totaled $0.9 million and working capital was $0.5 million. At December 31, 2009, cash and cash equivalents totaled approximately $1.1 million, and working capital was approximately $0.8 million. The decrease in working capital from the prior year is primarily due to the increase in the interest rate on the Amended Debenture during the fourth quarter of 2010 as required by the Plan. Restricted cash and advances from Atlas includes the cash received from Atlas restricted for drilling activities in connection with oil and gas properties subject to the Farmout Agreement.

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Capital Expenditures Substantial capital is required to replace and grow reserves. As a result the Company did not conduct any drilling operations for its own account in 2010 or 2009, although the Company did complete three previously drilled wells during 2010.

Cash Flows from Operations Cash flows used in operations totaled ($2.5) million and ($3.2) million during 2010 and 2009, respectively. Cash flow from operations is dependent upon the price of natural gas and our ability to increase production, and manage costs. Natural gas prices increased slightly in 2010 compared to 2009 but the Company experienced volumetric declines. Therefore, we were unable to generate the cash flows from operations necessary to sustain our working capital needs or contribute to our drilling program.

Cash Flows from Financing Activities The Company received a cash advance from WCOF on May 27, 2010 of $150,000. An additional cash advance of $100,000 was received from WCOF on July 2, 2010. Both advances, plus accrued interest at 10% per annum from the date of each advance, were due within 30 days of the Company s receipt of the cash payment for the well-site fees related to the first 60 wells drilled under the Farmout Agreement. All cash advances were repaid with interest in December 2010.

Management s Plans to Obtain Additional Capital

On July 23, 2010, the Company entered into the Farmout Agreement with Atlas relating to natural gas drilling within an area of mutual interest in the AMI. Since that time, our principal focus has been the execution of our obligations under that agreement. As such, the principal source of cash flow for our operations will be from the well site fees from drilling wells under the Farmout Agreement. The principal source of increasing natural gas sales will be from the 6% overriding royalty interest we have in the wells under the Farmout Agreement.

Our ability to continue as a going concern currently is dependent on the Farmout Agreement. If Atlas is unable to develop wells under the Farmout Agreement or elects not to continue the drilling program at the level of 60 wells per six month period, we will need to obtain additional capital. Cash and cash equivalents on hand and, internally generated cash flows will require augmentation from equity or debt financing to fund our debt service, working capital requirements, planned drilling, potential acquisitions and other capital expenditures in the future. The Company is pursuing acquisitions of under-exploited oil and gas properties with potential upside. The amount and allocation of future capital and exploitation expenditures will depend upon several factors including the number and size of acquisitions, drilling opportunities, future cash flows from operating and financing activities, and our ability to assimilate acquisitions. Also, the impact of oil and gas market prices on investment opportunities, the availability of capital and borrowing facilities and the success of our exploitation and development activities, particularly in Colorado, could lead to changes in funding requirements for future development.

The Company will continue to explore opportunities to raise capital, including a private placement of its common stock. There can be no assurances that the Company will be able to secure this additional financing and, accordingly, the Company s liquidity and ability to execute its business plan and to timely pay its obligations when due could be adversely affected. If we fail to secure equity financing for future development in a private placement of our common stock, we will pursue other financing options through debt arrangements, joint venture partners, or farmout agreements. We may be unable to raise additional capital in a timely manner, on acceptable terms or at all.

Off-Balance Sheet Arrangements As of December 31, 2010, the Company has no material off-balance sheet arrangements.

Critical Accounting Policies and Estimates

We are engaged in the exploration, exploitation, development, acquisition, and production of natural gas. Our discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements. The preparation of these consolidated financial statements requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses as well as the disclosure of contingent assets and liabilities as of the date of our financial statements. We base our decisions affecting the estimates we use on historical experience and various other sources that are believed to be reasonable under the circumstances. Actual results may differ from the estimates we calculate due to changes in business conditions or unexpected circumstances. Policies we believe are critical to understanding our business operations and results of operations are detailed below. For additional information on our significant accounting policies refer to Note 2 Summary of Significant Accounting Policies, Note 6 Asset Retirement Obligations, and Note 13 Disclosures about Oil and Gas Producing Activities in our consolidated financial statements included in Item 8 of this Annual Report.

Oil and gas reserve quantities. Estimated reserve quantities and the related estimates of future net cash flows are critical estimates for an exploration and production company because they affect the perceived value of our Company, are used in comparative financial analysis ratios and are used as the basis for the most significant accounting estimates in our financial statements. The significant accounting estimates primarily include the periodic calculations of depletion, depreciation, and impairment of our proved oil and gas properties. Future cash inflows and future production and development costs are determined by applying benchmark prices and costs, including transportation, quality, and basis differentials, in effect at the end of each period to the estimated quantities of oil and gas remaining to be produced as of the end of that period. Expected cash flows are reduced to present

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value using a discount rate that depends upon the purpose for which the reserve estimates will be used. Cash flows are calculated using average first of month pricing for the past 12 months and, the standardized measure calculations required by FASB ASC Topic 932 requires a ten percent discount rate to be applied. Although reserve estimates are inherently imprecise, and estimates of new discoveries and undeveloped locations are more imprecise than those of established producing oil and gas properties, we make a considerable effort in estimating our reserves, including using independent reserve engineering consultants. We expect that periodic reserve estimates will change in the future as additional information becomes available or as oil and gas prices and operating and capital costs change. We evaluate and estimate our oil and gas reserves for impairment at December 31each year, unless factors would indicate to us to evaluate our reserves more frequently. For purposes of depletion, depreciation, and impairment, reserve quantities are adjusted at all interim periods for the estimated impact of additions and dispositions. Changes in depletion, depreciation, or impairment calculations caused by changes in reserve quantities or net cash flows are recorded in the period that the reserve estimates change.

Successful efforts method of accounting. Generally accepted accounting principles provide for two alternative methods for the oil and gas industry to use in accounting for oil and gas producing activities. These two methods are generally known in our industry as the full cost method and the successful efforts method. Both methods are widely used. The methods are different enough that in many circumstances the same set of facts will provide materially different financial statement results within a given year. We have chosen the successful efforts method of accounting for our oil and gas producing activities, and a detailed description is included in Note 2 to our consolidated financial statements included in this annual report.

Depreciation, Depletion, Amortization and Accretion (DD&A). Our rate of recording DD&A is dependent upon our estimates of total proved and proved developed reserves, which estimates incorporate various assumptions and future projections. If the estimates of total proved or proved developed reserves decline, the rate at which we record DD&A expense increases, reducing our net income or increasing our net loss. Such a decline in reserves may result from lower commodity prices, which may make it uneconomic to drill for and produce higher cost fields. We are unable to predict changes in reserve quantity estimates as such quantities are dependent on the success of our exploitation and development program, as well as future economic conditions.

Revenue recognition. We derive our revenue primarily from the sale of produced natural gas. We report revenue as the gross amounts we receive before taking into account production taxes and transportation costs. Revenue is recorded in the month our production is delivered to the purchaser, but payment is generally received between 30 and 90 days after the date of production. No revenue is recognized unless it is determined that title to the product has transferred to a purchaser. At the end of each month we make estimates of the amount of production delivered to the purchaser and the price we will receive. We use our knowledge of our properties, their historical performance, local spot market prices, and other factors as the basis for these estimates. Variances between our estimates and the actual amounts received are recorded in the month payment is received. Historical differences have not been significant.

Asset retirement obligations. We are required to recognize an estimated liability for future costs associated with the abandonment of our oil and gas properties. We base our estimate of the liability on our historical experience in abandoning oil and gas wells projected into the future based on our current understanding of federal and state regulatory requirements. Our present value calculations require us to estimate the economic lives of our properties, assume what future inflation rates apply to external estimates, and determine what credit adjusted risk-free rate to use. The impact to the consolidated statement of operations from these estimates is reflected in our depreciation, depletion, and amortization calculations and occurs over the remaining life of our properties.

Valuation of long-lived assets. Our property and equipment are recorded at cost. Unproved properties are assessed periodically to ascertain whether impairment has occurred. Unproved properties whose costs are individually significant are assessed individually by considering the primary lease terms of the properties, the holding period of the properties, and geographic and geologic data obtained relating to the properties. Where it is not practicable to assess individually the amount of impairment of properties for which costs are not individually significant, such properties are grouped for purposes of assessing impairment. An impairment charge is taken on unproven property when we determine that the property will not be developed or the carrying value will not be realized. We evaluate the realizability of our proved properties and other long-lived assets whenever events or changes in circumstances indicate that impairment may be appropriate. Our impairment test compares the expected undiscounted future net cash flows from property, using escalated pricing, with the related net capitalized cost of the property at the end of each period. When the net capitalized costs exceed the undiscounted future net cash flows of a property, the cost of the property is written down to our estimate of fair value, which is determined by applying a discount rate that we believe is indicative of the current market. Our criteria for an acceptable internal rate of return are subject to change over time. Different pricing assumptions or discount rates could result in a different calculated impairment.

Income taxes. We provide for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in our financial statements in accordance with FASB ASC Topic 740, Income Taxes (ASC Topic 740). This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in determining when these events may occur and whether recovery of an asset is more likely than not. Additionally, our federal and state income tax returns are generally not filed before the consolidated financial statements are prepared, therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects

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of tax rate changes, tax credits, and net operating and capital loss carry-forwards and carry-backs. Adjustments related to differences between the estimates we used and actual amounts we report are recorded in the periods in which we file our income tax returns. These adjustments and changes in our estimates of asset recovery and liability settlement could have an impact on our results of operations. We recognize the impact of a tax position in our financial statements only if the technical merits of that position indicate that the position is more likely than not to be sustained upon audit, according to the uncertainty provisions of ASC Topic 740.

ITEM 7A. QUALITATIVE AND QUANTITATIVE DISCLOSURE OF MARKET RISK.

Not applicable.

ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

The consolidated financial statements required pursuant to this Item 8 are included in Item 15 of this Annual Report and begin on page F-1.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures.

Our Chief Executive Officer and Chief Financial Officer have reviewed and evaluated the effectiveness of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the Exchange Act), as of the end of the period covered by this Annual Report. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of the end of the period covered by this Annual Report on Form 10-K.

Management s Annual Report on Internal Control over Financial Reporting.

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act, to provide reasonable assurance that the objectives of the control system are met. Our management conducted an assessment of our internal control over financial reporting based on the framework established by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control Integrated Framework. The Company s internal control over financial reporting includes those policies and procedures that:

(i) Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company;

(ii) 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

(iii) Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company s assets that have a material effect on the financial statements.

Management assessed the effectiveness of the Company s internal control over financial reporting as of December 31, 2010. Based on our assessment and those criteria, management believes that the Company maintained effective internal control over financial reporting as of December 31, 2010.

This Annual Report does not include an attestation report of the Company s registered public accounting firm regarding internal control over financial reporting. Management s report was not subject to attestation by the Company s registered public accounting firm pursuant to rules of the SEC that permit the Company to provide only management s report in this Annual Report.

Changes in Internal Controls

There were no changes in our internal control over financial reporting during the fourth fiscal quarter of 2010 that have

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materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

ITEM 9B. OTHER INFORMATION.

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

Biographical information, including principal occupation and business experience during the last five years, of each member of our Board of Directors as of March 15, 2011 is set forth below.

Directors

Thomas E. Riley, age 58, joined us as Chairman and Chief Executive Officer in July 2009. Prior to joining Black Raven, he spent the prior 12 years growing Petroleum Development Corp. (PDC) (NASDAQ: PETD). Tom joined PDC in 1996 through a merger with his company Riley Natural Gas Co., and became its President in 2004. Mr. Riley founded and managed Riley Natural Gas Co. and RNG Service Co. for ten years prior to joining PDC. In addition, he spent six years at Consolidated Natural Gas Co. and seven years at Berea Oil & Gas Co. Mr. Riley holds a Petroleum Engineering degree from West Virginia University. We believe that Mr. Riley s financial and business expertise, including a diversified background of managing and directing oil and gas companies, gives him the qualifications and skills to serve as a director.

Gus J. Blass III, age 58, joined the Board in June 2006. He has been a General Partner of Capital Properties LLC since 1981. Capital Properties owns and manages over one million square feet of warehouse space in the Little Rock, Arkansas area and invests in public and private companies. Mr. Blass currently serves on the Board of Directors at Bancorp South, Cajuns Wharf Corporation and NutraCheck, Inc. Mr. Blass has a Bachelor of Science Degree in Finance and Banking from the University of Arkansas. We believe that Mr. Blass s financial and business expertise, including a diversified background of managing and directing public and private companies with substantial real property and serving on other boards of directors, gives him the qualifications and skills to serve as a director.

Daniel R. Frederickson, age 64, joined the Board in July 2009. He was the President of Kinko s Inc from 1986 to 1997. He is active in real estate ventures and serves on the Board of Directors for Culligan Water Co. Inc and Cydcor Inc. He holds a Bachelor of Science degree in Music from Central Missouri University and proudly served in Vietnam with the U.S. Marine Corps. We believe that Mr. Frederickson s financial, business and real property expertise in managing and directing several public companies and real estate ventures, gives him the qualifications and skills to serve as a director.

William F. Hayworth, age 56, joined us as President, Chief Operating Officer and Director in June 2004. He served as Chief Executive Officer from January 2008 to July 2009. He currently serves as our President. From 2002 to 2004, he served as a consultant through his wholly-owned company, BAM Energy, Inc., to various energy companies acting as project manager and evaluation specialist for coal-bed methane pilot projects in Kansas, Wyoming, western Colorado and Utah. From 1997 to 2002, he was Vice President-Operations for Intoil, Inc. in Denver. His responsibilities included management and coordination of the company s drilling and production activities as well as the design and construction of gathering facilities. Prior to 1997, he was employed by Unit Corporation in Houston, Texas and was the Engineering/Operations Manager for Patrick Petroleum in Houston, Texas and Jackson, Michigan. In addition to his responsibilities for supervision of technical staff and field personnel, Mr. Hayworth evaluated potential acquisitions and divestitures for Patrick Petroleum. He also spent 12 years with Phillips Petroleum where he held various reservoir drilling and production engineering positions in the United Kingdom, Norway, Texas and Oklahoma. Mr. Hayworth holds a Bachelor of Science degree in Chemical Engineering from the University of Michigan. He is a member of the American Association of Drilling Engineers, the Rocky Mountain Association of Geologists, the International Association of Drilling Contractors, the Society of Petroleum Engineers and the Energy Finance Group. We believe that Mr. Hayworth s financial and business expertise, including a diversified background of in the oil and gas industry, gives him the qualifications and skills to serve as a director.

Atticus Lowe, age 30, is the Chief Investment Officer and a Principal of Black Raven s largest stockholder, West Coast Asset Management, Inc., a Registered Investment Advisor. In addition to his extensive investment experience, Atticus has experience in the energy industry as a founder and principal of Black Sable Energy, LLC. Atticus is a Co-Author of The Entrepreneurial Investor (Published by John Wiley & Sons) and has been a featured speaker at the Value Investing Congress. He is a CFA Charterholder and holds a Bachelor of Arts degree in Economics and Business from Westmont College. We believe that Mr. Lowe s financial, investment and business expertise, including his work in the energy industry, gives him the qualifications and skills to serve as a director.

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Audit Committee

As of December 31, 2010, the Board had an Audit Committee and its members were Atticus Lowe (Chairman), Gus Blass and Dan Frederickson. Gus Blass and Dan Frederickson satisfied the independence standards specified in Rule 10A-3(b)(1) of the Exchange Act. Each member of the Audit Committee was financially literate and was able to read and understand fundamental financial statements, including the balance sheet, income statement and statement of cash flows. The Board has determined that Atticus Lowe qualified as an audit committee financial expert as defined in the Exchange Act. The Audit Committee operates pursuant to a written charter. As enumerated in the charter, the Audit Committee makes recommendations concerning the engagement of independent public accountants and reviews our quarterly and annual financial statements with the independent public accountants. The Audit Committee also reviews with the independent accountants the plans and results of the audit engagement, the range of audit and non-audit fees, and the integrity, adequacy and effectiveness of our disclosure controls and internal control over financial reporting. The Audit Committee oversees and periodically confirms the independence of our independent accountants, pre-approves services performed by our independent accountants and reviews the results of the audit and the independent accountant s report for each fiscal year with management and with the independent accountants. The Audit Committee also reviews all proposed transactions between us and persons that are considered related parties.

Stockholder Procedures to Nominate Directors

There were no material changes to stockholder procedures for nomination of directors during the year ended December 31, 2010.

Code of Ethics

We have adopted a Code of Business Conduct and Ethics to provide guidance on maintaining our commitment to being honest and ethical in our business endeavors. The Code of Business Conduct and Ethics covers a wide range of business practices, procedures and basic principles regarding corporate and personal conduct and applies to all of our directors, executives, officers and employees. A copy of the Code of Business Conduct and Ethics is filed as Exhibit 14.1 to our Annual Report on Form 10-K for the year ended December 31, 2005. In addition, a copy of the Code of Business Conduct and Ethics may be obtained, without charge, by written request submitted to the Secretary at Black Raven Energy, Inc., 1331 Seventeenth Street, Suite 350, Denver, Colorado 80202.

Executive Officers

The following table sets forth certain information regarding our executive officers as of December 31, 2010.

Name	Age	Positions
Thomas E. Riley	58	Chairman and Chief Executive Officer
William F. Hayworth	56	President
Patrick A. Quinn	57	Chief Financial Officer
David L. Kunovic	59	Vice President of Exploration

The principal occupation of each executive officer of the Company as of December 31, 2010, for at least the past five years, is as follows:

Thomas E. Riley More detailed information regarding Mr. Riley s business experience is set forth under Directors. Mr. Reilly became the Chief Executive Officer on July 13, 2009.

William F. Hayworth More detailed information regarding Mr. Hayworth s business experience is set forth under Directors. Mr. Hayworth became the Chief Executive Officer on January 31, 2008 and resigned July 7, 2009.

Patrick A. Quinn, was appointed as contract Chief Financial Officer for the Company on an interim basis as of January 10, 2010. Mr. Quinn brings more than 30 years of accounting experience to Black Raven, including 20 years as the President of Quinn & Associates, P.C., which provides accounting, audit, tax and merger and acquisition consulting services to businesses in the real estate, mining and oil and gas industries. He served as the Controller of Hamilton Oil Corporation from 1981 to 1986, the contract CFO of Teton Energy Corporation from 2004 to 2006, and the contract CFO of Intrepid Mining, LLC (predecessor to Intrepid Potash, Inc. (NYSE: IPI)) from 2000 to 2008. Mr. Quinn holds a Bachelor of Science degree in Accounting from Colorado State University.

***David L. Kunovic*,** joined the Company on October 1, 2010 as Vice President of Exploration. Mr. Kunovic has over 32 years experience as an exploration geologist, including 11 years as President of Kachina Energy, Inc., managing geologic and geophysical projects for several independent oil companies. He has also held positions as Vice President of Exploration for Canyon Energy, Inc. from 1994 2000 managing all exploration activities for the Rocky Mountain region; Petroleum Incorporated from 1991 1994 as Exploration Manager for all US exploration; Newport Exploration from 1984-1991 as Exploration Manager Rocky Mountain region; Apache Corporation from 1980-1984 as Senior Geologist working the Powder River and Denver Basins and Union Texas Petroleum from 1978-1980 as geologist Rocky Mountain Basins. Mr. Kunovic holds a Bachelors degree in Geology from the University of Colorado and also completed Masters level course work in Environmental Engineering and Groundwater at the University of

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Colorado.

ITEM 11. EXECUTIVE COMPENSATION.

Summary Compensation Table

(a) Name and Principal Position	(b) Year		(c) Salary ($)		(d) Bonus ($)		(e) Option Awards ($)(1)		(f) All Other Compensation ($)(2)		(g) Total ($)
Thomas E. Riley *Chief Executive Officer (3)*	2010	$	120,000	$		$		$	22,026	$	142,026
	2009	$	55,385	$		$		$	4,867	$	60,252
William Hayworth *President (4)*	2010	$	200,000	$		$	155,625	$	33,113	$	388,738
	2009	$	221,154	$		$	156,563	$	27,733	$	405,423
Patrick Quinn *Chief Financial Officer (5)*	2010	$		$		$	19,762	$		$	19,762
David Kunovic *Vice President of Exploration (6)*	2010	$	38,113	$		$	3,075	$	4,725	$	45,913

(1) The amounts reflect the total recognized for the year ended December 31, 2010 and 2009, in accordance with FASB ASC Topic 718, Compensation Stock Compensation (ASC Topic 718), for stock options and include amounts from awards granted in 2010 and 2009. Assumptions used in the calculation of this amount under the Black-Scholes method are included in footnote 11 to our consolidated financial statements for the year ended December 31, 2010.

(2) The amount shown reflects:

- Matching contributions pursuant to our 401(k) Savings Plan for Mr. Hayworth were $6,000 for 2010 and $6,635 for 2009. Matching contributions pursuant to our 401(k) Savings Plan for Mr. Riley were $3,600 for 2010 and $1,523 for 2009. Matching contributions pursuant to our 401(k) Savings Plan for Mr. Kunovic were $1,143 for 2010.

- Health care medical plan compensation for Mr. Hayworth was $27,113 for 2010 and $21,098 for 2009. Health care medical plan compensation for Mr. Riley was $18,426 for 2010 and $3,344 for 2009. Health care medical plan compensation for Mr. Kunovic was $4,725 for 2010.

(3) Mr. Riley became our Chief Executive Officer on July 13, 2009.

(4) Mr. Hayworth served as our Chief Executive Officer from January 31, 2008 to July 8, 2009 and currently serves as our President.

(5) Mr. Quinn was appointed as our Chief Financial Officer on January 10, 2010.

(6) Mr. Kunovic became our Vice President of Exploration on October 1, 2010.

Outstanding Equity Awards at Fiscal Year-End

(a)	(b)	(c)	(d)	(e)
	Option Awards			
Name	Number of Securities Underlying Unexercised Options (#) Exercisable (1)	Number of Securities Underlying Unexercised Options (#) Unexercisable (1)	Option Exercise Price ($)(1)	Option Expiration Date (1)
William Hayworth	250,000	500,000	2.00	7/1/2019
	125,000(2)		2.00	9/16/2019

(1) The options granted under the 2009 Equity Compensation Plan expire in ten years.

(2) These options vested immediately upon grant.

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Director Compensation

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)	Option Awards ($)	Total ($)
Gus Blass III	$ 2,000		$ 30,750	$ 32,750
Daniel Frederickson	$ 2,000		$ 30,750	$ 32,750

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

Equity Compensation Plan Information

The following table is a summary of the shares of our common stock authorized for issuance under our equity compensation plan as of December 31, 2010.

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans
Equity Compensation Plan Approved by Security Holders	4,165,241	$ 2.00	2,517,741
Equity Compensation Plan Not Approved by Security Holders	0	0	0
Total	4,165,241	$ 2.00	2,517,741

Beneficial Ownership

The following table sets forth information regarding beneficial ownership of our common stock as of December 31, 2010 by:

- each of our directors and named executive officers;
- all executive officers and directors as a group; and
- each person who is known by us to beneficially own more than 5% of our outstanding common stock.

Beneficial ownership of our common stock is based on 16,776,874 shares of common stock outstanding at March 18, 2011. Beneficial ownership of our common stock is determined in accordance with the rules of the SEC and generally includes any shares of common stock over which a person exercises sole or shared voting or investment powers, or of which such person has a right to acquire ownership at any time within 60 days of December 31, 2010. All shares listed below are held directly unless otherwise noted. Each director s and executive officer s address is c/o Black Raven Energy, Inc., 1331 Seventeenth Street, Suite 350, Denver, Colorado 80202.

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[redacted]		
Stockholders Owning More Than 5%:		
[redacted]		
Directors and Named Executive Officers:		
[redacted]		
Gus Blass III (2)	382,536	2.2%
[redacted]		
Atticus Lowe (4)	15,285,432	91.1%
[redacted]		

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* Less than 1%

(1) Includes 375,000 shares of common stock issuable upon exercise of stock options currently exercisable.

(2) Includes 141,268 common stock issuable upon the exercise of warrants, and 100,000 shares of common stock issuable upon exercise of stock options currently exercisable.

(3) Includes 100,000 shares of common stock issuable upon exercise of stock options currently exercisable.

(4) Mr. Lowe serves as Chief Investment Officer of West Coast Opportunity Fund, LLC. Mr. Lowe s beneficial ownership includes shares held by West Coast Opportunity Fund, LLC.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE.

Independence of Directors

The Board determined that Gus J. Blass III and Daniel Frederickson have no material relationship with us, directly or indirectly, that would interfere with the exercise of independent judgment.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The following table presents the aggregate fees billed for the indicated services performed by Deloitte & Touche LLP (Deloitte) for the 2010 and 2009 fiscal years

Deloitte	**2010**	**2009**
Audit fees	$ 170,000	$ 125,000

Audit-related fees				
All other fees				
Total fees	$	170,000	$	125,000

For purposes of the preceding table, the professional fees are classified as follows:

Audit Fees. This category includes the aggregate fees billed for professional services rendered for the audits of our consolidated financial statements for the years ended December 31, 2010 and December 31, 2009 and for the reviews of the financial statements included in our quarterly reports on Form 10-Q during these years. These services are normally provided by the independent public accountants in connection with statutory and regulatory filings or engagements for the relevant fiscal year. The Audit Committee approved the 2010 and 2009 audit fees.

Audit-Related Fees. This category includes the aggregate fees billed for the year ended December 31, 2010 for review of internal controls and related services by the independent public accountants that related to the performance of audits or reviews of the financial statements that are not reported above under Audit Fees.

All Other Fees. This category includes the aggregate fees billed for the 2010 and 2009 financials and reports and consists of out-of-pocket expenses, products and services provided by the independent public accountants that are not reported above under Audit fees or Audit-Related fees.

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PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

(1) Consolidated Financial Statements

The following consolidated financial statements are filed as part of this report:

Reports of Independent Registered Public Accounting Firms	F-1
Consolidated Balance Sheets	F-2
Consolidated Statements of Operations	F-4
Consolidated Statement of Changes in Stockholders Equity	F-5
Consolidated Statements of Cash Flows	F-6
Notes to Consolidated Financial Statements	F-7

(2) Financial Statement Schedules

All financial statement schedules are omitted because they are not required, are not applicable, or the information is provided elsewhere in the consolidated financial statements or notes thereto.

(3) Exhibit List

Exhibit Number	Description
2.1	Modified Second Amended Joint Plan of Reorganization Filed by PRB Energy, Inc. and PRB Oil & Gas, Inc., dated December 3, 2008 (incorporated herein by reference to Exhibit 99.1 to our Current Report on Form 8-K filed on January 21, 2009)
3.1	Amended and Restated Articles of Incorporation of Black Raven Energy, Inc. (incorporated herein by reference to Exhibit 3.1 to our Current Report on Form 8-K filed on February 6, 2009)
3.2	Amended and Restated Bylaws of Black Raven Energy, Inc. (incorporated herein by reference to Exhibit 3.2 to our Current Report on Form 8-K filed on February 6, 2009)
4.1	Amended and Restated Senior Secured Debenture (incorporated herein by reference to Exhibit 4.1 to our Current Report on Form 8-K filed on February 6, 2009)

4.2	Form of Warrant Certificate of Black Raven Energy, Inc. (incorporated herein by reference to Exhibit 10.2 to our Current Report on Form 8-K filed on February 6, 2009)
10.1	Limited Waiver, Consent, and Modification Agreement, dated February 2, 2009, by and among PRB Oil & Gas, Inc., Black Raven Energy, Inc. and West Coast Opportunity Fund, LLC (incorporated herein by reference to Exhibit 10.1 to our Current Report on Form 8-K filed on February 6, 2009)
10.2	Agreement Regarding New Equity Raise Under the Modified Second Amended Joint Plan of Reorganization, effective as of April 13, 2009, by and among Black Raven Energy, Inc., West Coast Opportunity Fund, LLC and the Official Committee of Unsecured Creditors (incorporated herein by reference to Exhibit 10.1 to our Current Report on Form 8-K filed on May 1, 2009)
10.3	Securities Purchase Agreement, dated April 23, 2009, by and between Black Raven Energy, Inc. and West Coast Opportunity Fund, LLC (incorporated herein by reference to Exhibit 10.2 to our Current Report on Form 8-K filed on May 1, 2009)
10.4	Securities Purchase Agreement, dated July 9, 2009, by and between Black Raven Energy, Inc. and West Coast Opportunity Fund, LLC (incorporated herein by reference to Exhibit 10.4 to our Annual Report on Form 10-K for the year ended December 31, 2007)
10.5	Securities Purchase Agreement, dated August 27, 2009, by and between Black Raven Energy, Inc. and West Coast Opportunity Fund, LLC (incorporated herein by reference to Exhibit 10.5 to our Annual Report on Form 10-K for the year ended December 31, 2007)
10.6	Securities Purchase Agreement, dated September 16, 2009, by and between Black Raven Energy, Inc. and West Coast Opportunity Fund, LLC (incorporated herein by reference to Exhibit 10.6 to our Annual Report on Form 10-K for the year ended December 31, 2007)

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10.7	Black Raven Energy, Inc. Equity Compensation Plan (the Equity Compensation Plan) (incorporated herein by reference to Exhibit 10.6 to our Annual Report on Form 10-K for the year ended December 31, 2007)
10.8	Form of Option Grant under the Equity Compensation Plan (incorporated herein by reference to Exhibit 10.7 to our Annual Report on Form 10-K for the year ended December 31, 2007)
10.9	Form of Restricted Stock Award Agreement under the Equity Compensation Plan (incorporated herein by reference to Exhibit 10.8 to our Annual Report on Form 10-K for the year ended December 31, 2007)
21.1	List of subsidiaries
23.1	Consent of MHA Petroleum Consultants, Inc.
24.1	Powers of Attorney, incorporated by reference to signature page attached hereto
31.1	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Securities Exchange Act of 1934 as adopted pursuant to Section 302 of the Sarbanes-Oxley Act
31.2	Certification of the Chief Financial Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Securities Exchange Act of 1934 as adopted pursuant to Section 302 of the Sarbanes-Oxley Act
32.1	Certification of the Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act

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Filed herewith

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Black Raven Energy, Inc.

Date: April 15, 2011

/s/ Thomas E. Riley
Thomas E. Riley
Chief Executive Officer

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

Signature	Title	Date
/s/ Thomas E. Riley Thomas E. Riley	Chief Executive Officer	April 15, 2011

/s/ Patrick A. Quinn Patrick A. Quinn	Chief Financial Officer	April 15, 2011
/s/ William F. Hayworth William F. Hayworth	President and Director	April 15, 2011
/s/ Gus J. Blass, III Gus J. Blass, III	Director	April 15, 2011
/s/ Atticus Lowe	Director	April 15, 2011

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Atticus Lowe

/s/ Dan Frederickson Dan Frederickson	Director	April 15, 2011

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To the Board of Directors and Stockholders of

Black Raven Energy, Inc.

Denver, Colorado

We have audited the accompanying consolidated balance sheets of Black Raven Energy, Inc. and its subsidiaries (the Company) as of December 31, 2010 and 2009, and the related consolidated statements of operations, stockholders deficit, and cash flows for each of the two 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 these 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 financial statements present fairly, in all material respects, the financial position of Black Raven Energy, Inc. and its subsidiaries at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Notes 1 and 3 to the financial statements, on January 16, 2009, the Bankruptcy Court entered an order confirming the Black Raven Energy, Inc. and PRB Oil and Gas, Inc. plan of reorganization which became effective on February 2, 2009. Also as discussed in Notes 1 and 3 to the financial statements, on February 17, 2010, PRB Gathering, Inc. was dismissed from Chapter 11 bankruptcy. Under the plan of reorganization, Black Raven Energy, Inc. and its subsidiaries are required to comply with certain terms and conditions as more fully described in Note 3 to the financial statements.

As discussed in Notes 2 and 13 to the consolidated financial statements, the Company changed its method of oil and gas reserve estimation and related required disclosures in 2009 with the implementation of new accounting guidance.

The accompanying financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 1 to the financial statements, the Company s recurring losses from operations and stockholders deficit raise substantial doubt about its ability to continue as a going concern. Management s plans concerning these matters are also discussed in Note 1 to the financial statements. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado

April 15, 2011

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Black Raven Energy, Inc. (formerly known as PRB Energy, Inc.)

Consolidated Balance Sheets

(In thousands, except share and per share amounts)

	December 31, 2010	December 31, 2009
Assets		
Current assets:		
Cash and cash equivalents	$ 948	$ 1,064
Restricted cash (Note 4)	5,637	
Accounts receivable, net	282	62
Inventory	53	62
Prepaid expenses	260	108
Total current assets	7,180	1,296
Oil and gas properties accounted for under the successful efforts method of accounting:		
Proved properties	5,113	4,626
Unproved leaseholds	3,375	5,842
Wells-in-progress	48	483
Total oil and gas properties	8,536	10,951
Less: accumulated depreciation, depletion and amortization	(1,265)	(1,212)
Net oil and gas properties	7,271	9,739
Gathering and other property and equipment:	2,962	2,964
Less: accumulated depreciation and amortization	(974)	(925)
Net gathering and other property and equipment	1,988	2,039
Other non-current assets:		
Deferred debt issuance costs, net		247
Other non-current assets	152	96
Total other non-current assets	152	343
TOTAL ASSETS	$ 16,591	$ 13,417

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

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Black Raven Energy, Inc. (formerly known as PRB Energy, Inc.)

Consolidated Balance Sheets (Continued)

(In thousands, except share and per share amounts)

	December 31, 2010	December 31, 2009
Liabilities and Stockholders Deficit		
Accounts payable	$ 1,234	238
Accrued expenses and other current liabilities	656	308
Advances from Atlas (Note 4)	4,824	
Total current liabilities	6,714	546
Secured debentures, net of discount	18,848	17,828
Asset retirement obligations	241	219
Investment in insolvent subsidiary		1,072
Total liabilities	25,803	19,665
Commitments and Contingencies (Note 8)		
Stockholders deficit		
Common stock, par value $.001, 150,000,000 shares authorized; 16,660,965 and 16,660,965 issued and outstanding for 2010 and 2009, respectively	17	17
Additional paid-in-capital	29,744	29,441
Accumulated deficit	(38,973)	(35,706)
Total stockholders deficit	(9,212)	(6,248)
TOTAL LIABILITIES AND STOCKHOLDERS DEFICIT	$ 16,591	$ 13,417

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

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Black Raven Energy, Inc. (formerly known as PRB Energy, Inc.)

Consolidated Statements of Operations

(In thousands except share and per share amounts)

[redacted]				
Revenue:				
Natural gas sales	$	469	$	460
Total revenue		469		460
Operating expenses:				
Natural gas production expense		776		616
Exploration expense		12		8
Depreciation, depletion, amortization and accretion		165		252
General and administrative		2,089		1,986
Total operating expenses		3,042		2,862
Operating loss		(2,573)		(2,402)
Other income (expense):				
Interest and other		11		14
Interest expense		(1,760)		(1,303)
Total other expense		(1,749)		(1,289)
Loss before reorganization items and income taxes		(4,322)		(3,691)
Reorganization items:				
Gain on reorganization		1,072		24,568
Loss on disposal of assets				(26)
Professional fees		(17)		(140)
Interest on accumulated cash resulting from Chapter 11 bankruptcy				3
Total reorganization items		1,055		24,405
Net income (loss) before income taxes		(3,267)		20,714
Income tax provision				
Net income (loss)	$	(3,267)	$	20,714
Net income (loss) per common share basic and diluted	$	(0.20)	$	1.37
Basic and diluted weighted average shares outstanding		16,660,965		15,086,117

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

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Black Raven Energy, Inc. (formerly known as PRB Energy, Inc.)

Consolidated Statements of Stockholders Deficit

Years Ended December 31, 2010 and 2009

(In thousands except share amounts)

	Common Shares	Common Amount	Treasury Shares	Treasury Amount	Additional Paid - In Capital	Accumulated Deficit	Total Stockholders Deficit
Balance at January 1, 2009	**8,721,994**	**$ 10**	**919,900**	**$ (1,257)**	**$ 26,922**	**$ (56,420)**	**$ (30,745)**
Cancellation of common stock in bankruptcy	(8,721,994)	(10)	(919,900)	1,257	(1,247)		
Issuance of common stock	14,994,298	15			(15)		
Sale of common stock	1,666,667	2			3,498		3,500
Share-based compensation					283		283
Net income						20,714	20,714
Balance at December 31, 2009	**16,660,965**	**17**			**29,441**	**(35,706)**	**(6,248)**
Share-based compensation					303		303
Net loss						(3,267)	(3,267)
Balance at December 31, 2010	**16,660,965**	**$ 17**		**$**	**$ 29,744**	**$ (38,973)**	**$ (9,212)**

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

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Black Raven Energy, Inc. (formerly known as PRB Energy, Inc.)

Consolidated Statements of Cash Flows

(In thousands except share amounts)

	Years Ended December 31, 2010	2009
Cash flows from operating activities		
Net income (loss)	$ (3,267)	$ 20,714
Adjustments to reconcile net income (loss) to net cash used in operating activities:		
Depreciation, depletion, amortization and accretion	165	252
Amortization of debt issuance costs	247	113
Amortization of discount on debentures	672	743
Bad debt expense	2	
Share-based compensation expense	303	283
Gain on reorganization	(1,072)	(24,568)
Loss on sale of assets and other	4	26
Changes in assets and liabilities:		
Restricted cash	(5,637)	
Accounts receivable	(222)	19
Inventory	9	(19)
Prepaid expenses	(152)	243
Other non-current assets	(56)	(31)
Accounts payable	998	(686)
Advances from Atlas	4,824	
Accrued expenses and other current liabilities	695	(220)
Net cash used in operating activities	(2,487)	(3,131)
Cash flows from investing activities		
Capital expenditures	(370)	(367)
Proceeds from Farmout Agreement (Note 4)	2,740	
Proceeds from sale of assets	1	1
Net cash provided by (used in) investing activities	2,371	(366)
Cash flows from financing activities		
Proceeds from loans from affiliate	250	
Proceeds from issuance of debt		1,500
Proceeds from issuance of common stock		3,500
Repayment of loans from affiliate	(250)	(911)
Net cash provided by financing activities		4,089
Net increase (decrease) in cash	(116)	592
Cash and cash equivalents beginning of year	1,064	472
Cash and cash equivalents end of year	$ 948	$ 1,064
Supplemental disclosure of cash flow activity		
Cash paid for interest	$ 137	$ 358
Supplemental schedule for non-cash activity		
Accrued capital expenditures	$ 6	$ 7
Conversion of interest to debt	$ 348	$

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

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BLACK RAVEN ENERGY, INC. (formerly known as PRB ENERGY, INC.)

Notes to Consolidated Financial Statements

December 31, 2010

Note 1 - General

Black Raven Energy, Inc. (Black Raven, the Company, us, our or we), formerly known as PRB Energy, Inc. (PRB Energy), operates as a independent energy company engaged in the acquisition, exploitation, development and production of natural gas and oil in the Rocky Mountain Region of the United States.

On March 5, 2008, PRB Energy and its subsidiaries filed voluntary petitions for relief for each business entity (the Chapter 11 Bankruptcy) under Chapter 11 of the Bankruptcy Code (the Bankruptcy Code) in the United States Bankruptcy Court for the District of Colorado (the Bankruptcy Court). PRB Energy continued to operate its business as a debtor-in-possession under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code.

On January 16, 2009, the Bankruptcy Court entered an order confirming PRB Energy s and PRB Oil and Gas, Inc. s (PRB Oil), a wholly-owned subsidiary of PRB Energy, Modified Second Amended Joint Plan of Reorganization (the Plan). The effective date of the Plan was February 2, 2009 (the Effective Date). Pursuant to the Plan, all of the issued and oustanding shares of PRB Energy s common stock were cancelled as of the Effective Date.and PRB Energy changed its corporate name to Black Raven Energy, Inc. The Plan provided that we continue as a public company following our emergence from bankruptcy and for the issuance of new common stock of Black Raven to certain claimants. After the Effective Date, PRB Oil was merged into the Company.

Effective November 1, 2008, control of the Recluse Gathering System owned by PRB Gathering, Inc. (PRB Gathering), a wholly-owned subsidiary of PRB Energy, was turned over to a receiver appointed by the State Court of Wyoming. Based on our loss of control, we deconsolidated PRB Gathering during the fourth quarter of 2008. The Company s investment/obligation with regard to the PRB Gathering business is reflected as an Investment in Insolvent Subsidiary in the accompanying balance sheets as of December 31, 2009. PRB Gathering was dismissed from Chapter 11 Bankruptcy on February 17, 2010, and a gain on reorganization was recognized for the amount of the Company s obligation for PRB Gathering. Upon dismissal from bankruptcy, the Company has reacquired control of PRB Gathering. PRB Gathering had no significant assets, liabilities or operations as of or for the year ended December 31, 2010.

The accompanying consolidated financial statements have been prepared assuming the Company will continue as a going concern. As shown in the accompanying financial statements, the Company continues to experience net losses from its operations, reporting a net loss before reorganization items of $4.3 million for the year ended December 31, 2010. Cash and cash equivalents on hand and internally generated cash flows may not be sufficient to execute the Company s business plan. Future bank financings, asset sales, or other equity or debt financings will be required to fund the Company s debt service, working capital requirements, planned drilling, potential acquisitions and other capital expenditures. These conditions raise substantial doubt about the Company s ability to continue as a going concern. These financial statements do not include any adjustments that may result from the outcome of this uncertainty.

During the quarter ended September 30, 2010, the Company entered into a Farmout Agreement, dated July 23, 2010 (the Farmout Agreement) with Atlas Resources, LLC (Atlas), as further discussed in Note 4. The Farmout Agreement is expected to provide the Company sufficient cash flow to continue drilling operations on behalf of Atlas on the properties subject to the agreement and to meet working capital requirements. There can be no assurances that the cash flow generated from the Farmout Agreement will be sufficient to execute the Company s business plan. The Company will also explore other opportunities to raise capital as needed to fund its debt service, potential acquisitions and other capital expenditures. There can be no assurances that the Company will be able to secure additional financing if and when necessary.

Note 2 - Summary of Significant Accounting Policies

Basis of Presentation - The consolidated financial statements include the accounts of the Company and its subsidiaries. These statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP). All inter-company transactions have been eliminated. In connection with the preparation of the consolidated financial statements, the Company evaluated subsequent events after the balance sheet date of December 31, 2010, through the filing date of this report.

For the period from March 5, 2008 through the Effective Date, we conducted our business in the ordinary course as debtors-in-possession under the protection of the Bankruptcy Court. We emerged from Chapter 11 Bankruptcy on February 2, 2009.

Our consolidated financial statements have been prepared in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 852, Reorganizations (ASC Topic 852), which requires that financial statements for periods subsequent to our Chapter 11 Bankruptcy filings distinguish transactions and events that are directly associated with the reorganization from the ongoing operations of the business. Accordingly, certain income, expenses, realized gains and losses and

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provisions for losses that were realized or incurred in our Chapter 11 Bankruptcy are recorded as reorganization items in our consolidated statements of operations.

At the Effective Date, we did not meet the requirements under ASC Topic 852 to adopt fresh start accounting. Fresh start accounting requires the debtor to use current fair values in its balance sheet for both assets and liabilities and to eliminate all prior earnings or deficits. The two requirements to fresh start accounting are:

- the reorganization value of the company s assets immediately before the date of confirmation of the plan of reorganization is less than the total of all post-petition liabilities and allowed claims; and

- the holders of existing voting shares immediately before confirmation of the plan of reorganization receive less than 50% of the voting shares upon emergence.

We refer to these requirements as the fresh start applicability test. For purposes of applying the fresh start applicability test, reorganization value is defined by ASC Topic 852 as the value attributed to the reconstituted entity, as well as the expected net realizable value of those assets that will be disposed before reconstitution occurs. Therefore, this value is viewed as the fair value of the entity before considering liabilities and approximates the amount a willing buyer would pay for the assets of the entity immediately after the restructuring.

As of the Effective Date, our fresh start calculation indicated that we did not meet the requirements to adopt fresh start accounting because the reorganization value of our assets exceeded the total of post-petition liabilities and allowed claims. The Company recognized a gain on reorganization of $24.6 million upon emergence from Chapter 11 bankruptcy.

Use of Estimates - The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Some specific examples of such estimates include the allowance for accounts receivable, accrued expenses, accrued revenue, asset retirement obligations, determining the remaining economic lives and carrying values of property and equipment and the estimates of gas reserves that affect the depletion calculation and impairments for gas properties and other long-lived assets. In addition, we use assumptions to estimate the fair value of share-based compensation. We believe our estimates and assumptions are reasonable; however, actual results may differ from our estimates.

Cash and Cash Equivalents - The Company considers all highly liquid instruments purchased with an original maturity of three months or less to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value due to the short-term nature of these instruments. The Company continually monitors its positions with, and the credit quality of, the financial institutions with which it invests.

Restricted Cash Restricted cash includes cash received from Atlas restricted for drilling activities in connection with oil and gas properties subject to the Farmout Agreement. See Note 4 for further discussion of Farmout Agreement.

Accounts Receivable - Trade accounts receivable are recorded at the invoiced amount. The Company assesses credit risk and allowance for doubtful accounts on a customer specific basis. The Company had an allowance for doubtful accounts of $2,000 at December 31, 2010 and no allowance for doubtful accounts at December 31, 2009.

The Company grants credit in the normal course of business to customers in the United States. The Company periodically performs credit analysis and monitors the financial condition of its customers to reduce credit risk. Management periodically reviews accounts receivable aging reports to assess credit risks, and if appropriate, also reviews updated credit information to further assess such risk. In the event that management determines the customers accounts receivable collectability as less than probable, management reduces the carrying amount by a valuation allowance that reflects management s best estimate of the amount not collectible. Allowances for uncollectible accounts receivable are based on information available and historical experience. For information on the concentration of credit risk by customer in the years ended December 31, 2010 and 2009, see below.

Inventory - Inventory is recorded at cost. The Company periodically reviews the carrying cost of its inventories as compared to current market value for those inventories and adjusts its carrying value to the lower of cost or market. Inventory at December 31, 2010 and 2009 consisted primarily of tubing, and totaled $53,000 and $62,000, respectively.

Income Taxes The Company recognizes deferred tax liabilities and assets based on the differences between the tax basis of assets and liabilities and their reported amounts in the consolidated financial statements that will result in taxable or deductible amounts in future years. In evaluating the ability to realize net deferred tax assets, the Company will take into account a number of factors, primarily relating to the Company s ability to generate taxable income. The Company has recognized, before the valuation allowance, a net deferred tax asset attributable to the net operating losses for the years ended December 31, 2010 and 2009, respectively. FASB ASC Topic 740, Income Taxes (ASC Topic 740), requires that a valuation allowance be recorded against deferred tax assets unless it is

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more likely than not that the deferred tax asset will be utilized. As a result of this analysis, the Company has recorded a full valuation allowance against its net deferred tax asset.

The Company has adopted the uncertainty provisions of ASC Topic 740, which requires the Company to recognize the impact of a tax position in its financial statements only if the technical merits of that position indicate that the position is more likely than not of being sustained upon audit. We recognize potential accrued interest and penalties, if any, related to unrecognized tax benefits in income tax expense, which is consistent with the recognition of these items in prior reporting periods. Due to the significant net operating losses, no interest and penalties were accrued.

Revenue Recognition - Revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if the collectability of the revenue is probable. The Company derives revenue primarily from the sale of produced natural gas. The Company reports revenue as the gross amount received before taking into account production taxes and transportation costs, which are reported as separate expenses. Revenue is recorded in the month the Company s production is delivered to the purchaser, but payment is generally received between 30 and 90 days after the date of production. Revenues from the production of gas properties in which the Company has an interest with other producers are recognized on the basis of the Company s net working interest. At the end of each month, the Company calculates a revenue accrual based on the estimates of production delivered to or transported for the purchaser.

Property, Equipment - Gas Gathering and Other - Gathering assets, including compressor sites and pipelines, are recorded at cost and depreciated using the straight line method over 10 years. Other property and equipment, such as office furniture, computer and related software and equipment, automobiles and leasehold improvements are recorded at cost. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets or underlying leases, in respect to leasehold improvements, ranging from three to ten years.

Oil and Gas Producing Properties We have elected to follow the successful efforts method of accounting for our oil and gas properties. Under this method of accounting, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the well has found proved reserves. If an exploratory well does not find proved reserves, the costs of drilling the unsuccessful exploratory well are charged to expense. Exploratory dry hole costs are included in cash flows from investing activities as part of capital expenditures in the consolidated statements of cash flows. The cost of development wells, whether productive or not, is capitalized.

Other exploration costs, including certain geological and geophysical expenses and delay rentals for oil and gas leases, are charged to expense as incurred. The sale of a partial interest in a proved property is accounted for as a cost recovery and no gain or loss is recognized as long as this treatment does not significantly affect the unit-of-production amortization rate. A gain or loss is recognized for all other sales of proved properties. Unproved oil and gas property costs are transferred to proved oil and gas properties if the properties are determined to be productive and are assigned proved reserves. Proceeds from sales of partial interests in unproved properties are accounted for as a recovery of cost without recognizing gain until all costs are recovered. Maintenance and repairs are charged to expense, and renewals and betterments are capitalized to the appropriate property and equipment accounts.

Depreciation, depletion, amortization and accretion (DD&A) of capitalized costs of proved oil and gas properties is determined on a field-by-field basis using the units-of-production method based upon proved reserves. The computation of DD&A takes into consideration restoration, dismantlement and abandonment costs and the anticipated proceeds from equipment salvage.

Impairment of Long-Lived Assets - In accordance with FASB ASC Topic 360, Property, Plant and Equipment (ASC Topic 360), we group assets at the field level and periodically review the carrying value of our property and equipment to test whether current events or circumstances indicate that such carrying value may not be recoverable. If the tests indicate that the carrying value of the asset is greater than the estimated future undiscounted cash flows to be generated by such asset, then an impairment adjustment will be recognized. Such adjustment consists of the amount by which the carrying value of such asset exceeds its fair value. We generally measure fair value by considering sale prices for similar assets or by discounting estimated future cash flows from such asset using an appropriate discount rate. Considerable management judgment is necessary to estimate the fair value of assets, and accordingly, actual results could vary significantly from such estimates.

The Company did not incur any impairment charges during the years ended December 31, 2010 and 2009.

Discount of Debt - On the Effective Date, we issued an Amended and Restated Senior Secured Debenture (the Amended Debenture) payable to West Coast Opportunity Fund, LLC (WCOF) in the amount of $18,450,000. We recorded a $1.4 million discount on the Amended Debenture upon issuance. The discount on the Amended Debenture was amortized using the retrospective interest method and was fully amortized at December 31, 2010. The discount is included in the balance of the Amended Debenture at December 31, 2009. For the year ended December 31, 2010, the Company recorded $672,000 of interest expense related to the amortization of the discount on its Amended Debenture. The interest expense related to the amortization of the discount for the year ended December 31, 2009 was $743,000.

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Exploration Expense - We account for exploration and development activities utilizing the successful efforts method of accounting. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for oil and gas leases are charged to expense as incurred. Drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found proved reserves in commercial quantities. The application of the successful efforts method of accounting requires managerial judgment to determine that proper classification of wells designated as developmental or exploratory is made to determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Wells may be completed that are assumed to be productive but actually deliver oil and gas in quantities insufficient to be economic. This may result in the abandonment of the wells at a later date. Wells are drilled that have targeted geologic structures that are both developmental and exploratory in nature and an allocation of costs is required to properly account for the results. The evaluation of oil and leasehold acquisition costs requires managerial judgment to estimate the fair value of these costs with reference to drilling activity in a given area.

Asset Retirement Obligations - We follow FASB ASC Topic 410, Asset Retirement and Environmental Obligations (ASC Topic 410), to account for our future asset abandonment costs. Estimated future costs associated with the plugging and abandonment of our oil and gas properties are discounted to present values using a risk-adjusted rate over the estimated economic life of the assets. Such costs are capitalized as part of the cost of the related asset and amortized over the related asset s estimated useful life. The associated liability is classified as a long-term liability and is adjusted when circumstances change and for the accretion of expense which is recorded as a component of depreciation, depletion and amortization. We recognize an estimate of the liability associated with the abandonment of oil and gas properties at the time the well is completed. We estimated our asset retirement obligation liabilities for these wells based on estimated costs to plug and abandon the wells, the estimated life of the wells and our respective ownership percentage in the wells.

Share-Based Compensation - At December 31, 2010, we had a stock-based employee compensation plan that includes stock options issued to employees and non-employee directors as more fully described in Note 11. We record expense associated with the fair value of stock-based compensation in accordance with FASB ASC Topic 718, Compensation Stock Compensation (ASC Topic 718). We use the Black-Scholes option valuation model to determine the fair value of awards and calculate the required disclosures.

We recorded compensation expense associated with all unvested stock options totaling $303,000 and $283,000 for the years ended December 31, 2010 and 2009, respectively.

Net Income (Loss) Per Share We account for earnings (loss) per share (EPS) in accordance with FASB ASC Topic 260, Earnings per Share (ASC Topic 260). Under ASC Topic 260, basic EPS is computed by dividing the net income (loss) applicable to common stockholders by the weighted average common shares outstanding without including any potentially dilutive securities. Diluted EPS is computed by dividing the net income (loss) applicable to common stockholders for the period by the weighted average common shares outstanding plus, when their effect is dilutive, common stock equivalents.

Potentially dilutive securities, which have been excluded from the determination of diluted earnings per share because their effect would be anti-dilutive, are as follows:

	For the years ended December 31,	
	2010	**2009**
Warrants	1,494,298	1,494,298

Options	1,647,500	1,332,500
Total potentially dilutive shares excluded	3,141,798	2,826,798

Subsequent to December 31, 2010, the Company did not issue any dilutive securities that would have increased the number of potentially dilutive shares.

Comprehensive Income (Loss) - We account for comprehensive income (loss) in accordance with FASB ASC Topic 220, Comprehensive Income (ASC Topic 220), which established standards for the reporting and presentation of comprehensive income in our consolidated financial statements. For the years ended December 31, 2010 and 2009, comprehensive income (loss) is equal to net income (loss) as reported in our consolidated statements of operations.

Off-Balance Sheet Arrangements - We have not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities (SPEs), or SPEs which would have been established for the purpose of facilitating off-balance sheet arrangements or for other contractually narrow or limited purposes.

Related Party Transactions - Atticus Lowe, who is a member of our Board of Directors, serves as Chief Investment Officer of West Coast Opportunity Fund, LLC, which owned 91% of the Company s common stock at December 31, 2010. See Note 3 for a description of the Company s transactions with West Coast Opportunity Fund, LLC.

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Fair Value of Financial Instruments - Our financial instruments, including cash and cash equivalents, restricted cash, accounts receivable, accounts payable, and secured debentures, are carried at cost. At December 31, 2010 and 2009, the fair value of the cash and cash equivalents, restricted cash, accounts receivable, and accounts payable, approximates their carrying value due to the short term nature of these instruments. Due to the nature of the Company s secured debentures, the Company is unable to reliably estimate their fair value at December 31, 2010 and December 31, 2009.

Concentration of Credit Risk - Revenues from customers which represented 10% or more of the Company s sales for the years ended December 31, 2010 and 2009 were as follows:

	For the years ended December 31,	
Customer	**2010**	**2009**
A	71.5%	71.0%
B	27.5%	29.0%
	99.0%	100.0%

Industry Segment and Geographic Information - The Company operates in one industry segment, which is in the exploration, development and production of natural gas and all of the Company s operations are conducted in the continental United States. Consequently, the Company currently reports as one industry segment.

Recent Accounting Pronouncements

In January 2010, the FASB issued ASC Update 2010-06, Fair Value Measurements and Disclosures (ASC Update 2010-06), which requires additional disclosures about the different classes of assets and liabilities measured at fair value, the valuation techniques and inputs used, the fair value measurements of the activity in Level 3 on a gross basis and the transfers between Levels 1 and 2. This new authoritative guidance was effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosures regarding gross activity in the Level 3 rollforward, which are effective for the Company as of January 1, 2011. The adoption of ASC Update 2010-06 did not have a material impact on the Company s financial statements.

On December 31, 2008, the SEC published final rules and interpretations updating its oil and gas reporting requirements. Many of the revisions are updates to definitions in the existing oil and gas rules to make them consistent with the petroleum resource management system, which is a widely accepted standard for the management of petroleum resources that was developed by several industry organizations. Key revisions include changes to the pricing used to estimate reserves, the ability to include nontraditional resources in reserves, the use of new technology for determining reserves, and permitting disclosure of probable and possible reserves. The Company adopted these new rules and interpretations as of December 31, 2009.

The FASB aligned ASC Topic 932 with all of the aforementioned SEC requirements by issuing ASC Update 2010-03. The Company has adopted the new authoritative guidance as of December 31, 2009.

Note 3 Emergence from Chapter 11 Bankruptcy

As discussed in Note 1, on March 5, 2008, PRB Energy and its subsidiaries filed voluntary petitions for relief for each business entity in Chapter 11 bankruptcy. PRB Energy continued to operate its business as a debtor-in-possession under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code.

On January 16, 2009, the Bankruptcy Court entered an order confirming the Plan, with an Effective Date of February 2, 2009. Pursuant to the Plan, all of the issued and outstanding shares of PRB Energy s common stock were cancelled as of the Effective Date and PRB Energy changed its corporate name to Black Raven Energy, Inc. The Plan provided that we continue as a public company following our emergence from bankruptcy and for the issuance of new common stock of Black Raven to certain claimants. Upon emergence from Chapter 11 bankruptcy, the Company recognized a gain on reorganization totaling $24,568,000.

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Pursuant to the terms of the Plan, the Company issued 1,419,339 shares of common stock, along with one warrant for each share at an exercise price of $2.50 per share, on a pro-rata basis to the holders of the Convertible Notes. The Company issued an additional 74,959 shares of common stock, along with one warrant for each share at an exercise price of $2.50 per share, on a pro-rata basis to the other claimants related to accounts payable and accrued expenses and other current liabilities. The Company also issued 13.5 million shares of common stock to WCOF, the principal pre-petition secured creditor.

After the Effective Date of the Plan, PRB Oil was merged into the Company.

Effective November 1, 2008, control of the Recluse Gathering System owned by PRB Gathering was turned over to a receiver appointed by the State Court of Wyoming. Based on our loss of control, we deconsolidated PRB Gathering during the fourth quarter of 2008. The Company s investment/obligation with regard to the PRB Gathering business is reflected as an Investment in Insolvent Subsidiary in the accompanying balance sheet as of December 31, 2009. PRB Gathering was dismissed from Chapter 11 Bankruptcy on February 17, 2010, and a gain on reorganization of $1,072,000 was recognized. Upon dismissal from bankruptcy, the Company has reacquired control of PRB Gathering. PRB Gathering had no significant assets, liabilities or operations as of or for the year ended December 31, 2010.

Note 4 Farmout Agreement

On July 23, 2010, the Company entered into a Farmout Agreement with Atlas, a wholly-owned subsidiary of Atlas Energy, Inc, relating to natural gas drilling within an area of mutual interest in Phillips and Sedgwick counties, Colorado and Perkins, Chase and Dundy counties, Nebraska (the AMI).

Under the terms of the Farmout Agreement, Atlas agreed to drill six initial wells identified in the Farmout Agreement (the Initial Wells) and to complete certain initial projects, including 3D seismic shoots, upgrades of sales meter equipment, and the change-out of compressors and upgrade of a dehydrator at the Company s facility. The Company assigned to Atlas all of its title and interest in the defined areas around the planned wellbores (the Drilling Units) for the Initial Wells.

The Farmout Agreement also provides for Atlas, at its discretion, to drill additional wells in the AMI in accordance with work plans (each a Work Plan) approved by Atlas under the Farmout Agreement. The initial Work Plan approved by Atlas covering the period from July 23, 2010 to April 30, 2011 provides for Atlas, at its discretion, to drill 60 additional wells. For each six month period after April 30, 2011, Atlas must submit a proposal to the Company setting forth the numbers of wells that it proposes to drill for such six month period (the Drilling Proposal) and the Company must provide a Work Plan to be approved by Atlas outlining the development plan for the wells set forth in the Drilling Proposal. In the event that Atlas determines not to drill at least 60 wells in the course of any six month period, the Company has the right, during such six month period, to drill for its own account that number of wells equal to the difference between 60 wells and the number of wells agreed to be drilled by Atlas. Upon payment of a well-site fee, delivery of an executed authorization for expenditure (AFE) for such well by Atlas, and completion of drilling the applicable well, the Company will assign all of its rights, title and interest in the Drilling Units established for such well. The Farmout Agreement also provides for certain rights of the Company and Atlas with respect to the drilling of deep wells and for the payment by Atlas of drilling and future 3D seismic costs.

As of December 31, 2010, drilling of the Initial Wells had been completed, and Atlas had funded and drilled an additional 23 wells pursuant to the initial Work Plan. The accounts payable balance at December 31, 2010 contains $813,000 of drilling costs related to the Farmout Agreement. Since December 31, 2010, an additional 17 wells have been funded and drilled.

In consideration for the agreements made under the Farmout Agreement, Atlas paid the Company $1,000,000 upon execution of the Farmout Agreement. Such amount has been shown as a recovery of the cost of the Company s proved and unproved oil and gas properties, as applicable. In addition, Atlas agreed to pay the Company a $60,000 well-site fee for each well drilled by Atlas in the AMI, including the Initial Wells. As of December 31, 2010, the Company had received $1,740,000 of well site fees for 29 wells drilled through December 31, 2010. The well site fees received have been recorded as a recovery of the cost of the Company s oil and gas properties. The Company will recognize gains on any well-site fees received for future drilling under the Farmout Agreement at such time that all costs related to the oil and gas properties subject to the Farmout Agreement have been recovered.

The Company will also receive an undivided six percent of eight eighths (6% of 8/8ths) overriding royalty interest on substantially all of the oil and gas produced and sold that is attributable to the Drilling Units assigned to Atlas under the Farmout Agreement, subject to certain deductions.

The term of the Farmout Agreement is ten years, subject to earlier termination pursuant to the terms set forth therein.

On August 11, 2010, in connection with the Farmout Agreement and ongoing investment advisory services, the Company entered into an advisory fee agreement with a third party, whereby the Company agreed to pay $10,000 per well for the first 220 wells that are funded and drilled by Atlas under the Farmout Agreement discussed above, up to a maximum fee of $2.2 million. As of December 31, 2010, Atlas had funded and drilled 29 wells, and the Company had paid an advisory fee of $290,000.

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Restricted cash includes cash received from Atlas restricted for drilling activities in connection with oil and gas properties subject to the Farmout Agreement.

Note 5 - Gathering and Other Property and Equipment

Gathering and other property and equipment consists of the following:

	Useful Lives	December 31, 2010 (in thousands)	December 31, 2009 (in thousands)
Compressor sites, pipelines and interconnect	10-30 years	$ 2,386	$ 2,386
Equipment	5 years	16	16
Computer equipment	3 years	247	277
Office furniture and equipment and related assets	5-7 years	141	135
Automobiles	3 years	172	150
		2,962	2,964
Less accumulated depreciation and amortization		(974)	(925)
Total		$ 1,988	$ 2,039

Note 6 - Asset Retirement Obligations

The Company recognizes an estimated liability for future costs associated with the abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation and corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is completed or acquired. The increase in carrying value is included in proved oil and gas properties in the accompanying consolidated balance sheets. The Company depletes the amount added to proved oil and gas property costs and recognizes expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective oil and gas properties. Cash paid to settle asset retirement obligations is included in the operating section of the Company s accompanying consolidated statements of cash flows.

The Company s estimated asset retirement obligation liability is based on historical experience in abandoning wells, estimated economic lives, estimates as to the cost to abandon the wells in the future, and federal and state regulatory requirements. The liability is discounted using the credit-adjusted risk-free rate estimated at the time the liability is incurred or revised. Revisions to the liability could occur due to changes in estimated abandonment costs or well economic lives, or if federal or state regulators enact new requirements regarding the abandonment of wells.

The following table details all changes to the Company s estimated asset retirement obligation liabilities during the years ended December 31, 2010 and 2009:

	For the Year Ended December 31, 2010		2009
	(in thousands)		
Asset retirement obligations, beginning of period	$ 219	$	345
Liabilities incurred			
Liabilities settled			
Sale of assets			
Accretion expense	22		20
Revision to estimated cash flows			(146)
Asset retirement obligations, end of period	$ 241	$	219

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Note 7 - Income Taxes

Income tax expense (benefit) for each of the years ended December 31, 2010 and 2009 are as follows:

(in thousands)	**2010**	**2009**
Current:		
Federal	$	$
State & Local		
Total current		
Deferred:		
Federal		
State & Local		
Total deferred		
Total income tax expense	$	$

Total income tax expense (benefit) differed from the amounts computed by applying the federal statutory income tax rate of 35% to earnings (loss) before income taxes as a result of the following items for the years ended December 31, 2010 and 2009:

(in thousands)	**2010**	**2009**
Statutory income tax expense (benefit)	$ (1,143)	$ 7,250
State income tax expense (benefit), net of federal income tax expense (benefit)	(116)	(61)
Other permanent items	(205)	533
Gathering deferred tax assets and other	(4,067)	
Change in valuation allowance	5,531	(7,722)
Income tax expense	$	$

For 2010, the reported amount of income tax expense differs from the amount that would result from applying domestic federal statutory tax rates to pretax losses, primarily due to the inclusion of PRB Gathering deferred tax assets post dismissal from bankruptcy.

Deferred income tax assets and liabilities are recognized for the future tax consequences of temporary differences. Temporary differences arise when revenues and expenses for financial reporting are recognized for tax purposes in a different period. The Company has recognized, before the valuation allowance, a net deferred tax asset. ASC Topic 740, Income Taxes (ASC Topic 740), requires that a valuation allowance be recorded against deferred tax assets unless it is more likely than not that the deferred tax asset will be utilized. As a result of this analysis, the Company has recorded a full valuation allowance against its net deferred tax asset. The Company will continue to evaluate the need to record valuation allowances against deferred tax assets and will make adjustments in accordance with the accounting standard.

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and liabilities at December 31, 2010 and 2009 are as follows:

(in thousands)	2010	2009
Deferred tax assets:		
Oil and gas properties	$ 564	$ 808
Asset retirement obligation	92	139
Other	244	111
Net operating loss carryforwards	13,726	8,010
	14,626	9,068
Valuation allowance	(13,869)	(8,338)
Net deferred tax asset	$ 757	$ 730
Deferred tax liabilities:		
Property and equipment	$ (757)	$ (398)
Amortization of debt discount		(332)
Deferred tax liability	(757)	(730)
Net deferred tax asset (liability)	$	$

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The Company may from time to time be assessed interest or penalties by major tax jurisdictions, although there have been no such assessments historically. In the event the Company receives an assessment for interest and/or penalties, such an assessment would be classified in the financial statements as income tax expense.

At December 31, 2010, the Company has net operating loss carryforwards for U.S. federal income tax purposes of approximately $37.5 million. These net operating loss carryforwards, if not utilized to reduce taxable income in future periods, will expire in various amounts beginning in 2028. This net operating loss carryforward may be subject to U.S. Internal Revenue Code Section 382 limitations.

The Company has recorded a valuation allowance of $13.9 million and $8.3 million for December 31, 2010 and 2009, respectively, against its net deferred tax asset. The change in valuation relates to current year activity and the inclusion of PRB Gathering deferred tax assets that have a full valuation.

The uncertainty provisions of ASC Topic 740 require the Company to recognize the impact of a tax position in its financial statements only if the technical merits of that position indicate that the position is more likely than not of being sustained upon audit. During 2010, the Company did not record a change to the reserve for uncertain tax positions. The tax years 2004 - 2009 are open and subject to audit by the Internal Revenue Service and the State of Colorado..

The tabular reconciliation of the reserve for uncertain tax benefits for the year ended December 31, 2010 is presented below.

(in thousands)	**2010**	**2009**
Beginning balance	$ 390	$ 390
Additions based on tax positions related to the current year		
Additions based on tax positions of prior years		
Reduction for tax positions of prior years		
Settlements		
Ending balance	$ 390	$ 390

Note 8 - Commitments and Contingencies

Commitments

In the normal course of business operations, the Company has entered into operating leases for office space, office equipment, vehicles and compression equipment. Rental payments under these operating leases and service agreements totaled $115,000 and $90,000 for the periods ended December 31, 2010 and 2009, respectively.

Future payments, by year, under these operating leases are as follows:

		(in thousands)
2011	$	115
2012		130
2013		127
2014		127
Thereafter		56
Total	$	555

Note 9 - Borrowings

Amended Debenture

On February 2, 2009, in connection with the consummation of the Plan, we, along with our subsidiary PRB Oil, entered into a Modification Agreement with WCOF. Under the Modification Agreement, we issued the Amended Debenture, payable to WCOF in the amount of $18.45 million. The Amended Debenture superseded and amended the senior secured debentures issued by PRB Oil to WCOF

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and DKR Soundshore Oasis Holding Fund Ltd. on December 28, 2006. We guaranteed payment of the Amended Debenture and pledged substantially all of our assets as collateral. If we fail to comply with the restrictions in the agreements governing the Amended Debenture, an event of default could occur that would permit the lenders to foreclose on substantially all of our assets. Under the terms of the Amended Debenture, $3.75 million of the outstanding principal balance and unpaid accrued interest were initially due on December 31, 2009, with the remainder of the outstanding balance and unpaid accrued interest due on December 31, 2010. The Amended Debenture accrued interest at 10% per annum payable quarterly.

On April 13, 2009, Black Raven, WCOF and the Official Committee of Unsecured Creditors Appointed by the Bankruptcy Court entered into an Agreement Regarding New Equity Raise Under the Modified Second Amended Joint Plan of Reorganization (the New Equity Agreement). The New Equity Agreement modified the obligations of the parties under the Plan and released WCOF from its obligation to raise or guarantee $7.5 million of additional funding for us. The New Equity Agreement required WCOF to purchase 166,667 shares of the New Common Stock from us for $3.00 per share within 10 business days of the New Equity Agreement and an additional $3 million of New Common Stock, preferred stock or convertible debt securities from time to time prior to September 10, 2010, at a purchase price of $2.00 per share. The New Equity Agreement also modified the interest rate under the Amended Debenture and extended the maturity date of the Amended Debenture to December 31, 2011.

On November 9, 2009, the Amended Debenture was further amended to increase the principal amount to $18.5 million in lieu of paying $50,000 in interest to WCOF.

On July 23, 2010, the Company and WCOF entered into the Third Amendment to the Amended Debenture (the Third Amendment). Pursuant to the terms of the Third Amendment, the Amended Debenture was amended as follows: (i) all current unpaid and accrued interest was added to the outstanding principal balance of the Amended Debenture, (ii) for the period from July 1, 2010 through December 31, 2011, the Company would not be required to make any payments of accrued interest on the Amended Debenture and such accrued interest would be added to the outstanding principal balance, and (iii) no event of default shall occur on the Amended Debenture until written notice of default is given to the Company by WCOF and such default shall have continued for a period of 30 days after written notice is delivered to the Company.

On October 12, 2010, the Company and WCOF entered into the Fourth Amendment to the Amended Debenture (the Fourth Amendment). Pursuant to the terms of the Fourth Amendment, the Amended Debenture was amended as follows: (i) the maturity date was extended to January 15, 2014, (ii) interest would be paid to WCOF on any outstanding principal at a rate equal to five percent (5%) per annum payable in shares of common stock of the Company in an amount based on a share price of $2.00 per share (the Stock Interest) and (iii) additional interest would be paid to WCOF on any outstanding principal at a rate equal to five percent (5%) per annum payable in cash (the Cash Interest). The Stock Interest is due and payable to WCOF quarterly in arrears on the last day of each calendar quarter, commencing with the calendar quarter ending on December 31, 2010. The Cash Interest is due and payable to WCOF on the maturity date of the Debenture, less $5,000 per well drilled under the Farmout Agreement, which will be paid to WCOF upon the Company s receipt of well-site fees from Atlas in accordance with the Farmout Agreement. Additionally, the Company and WCOF agreed that no event of default shall occur on the Amended Debenture until written notice of default is given to the Company by WCOF and such default shall have continued for a period of 30 days after written notice is delivered to the Company.

The Company is in compliance with all the terms, conditions and covenants of the Amended Debenture, as amended, as of December 31, 2010 and 2009.

Short-Term Borrowings from Affiliate

The Company received a cash advance of $150,000 from WCOF on May 27, 2010 . An additional cash advance of $100,000 was received from WCOF on July 2, 2010. Both advances, plus accrued interest at 10% per annum from the date of each advance, were due within 30 days of the Company s receipt of the cash payment for the well-site fees related to the first 60 wells drilled under the Farmout Agreement. All cash advances were repaid with interest in December 2010.

PRB Funding Prepetition Loan

Immediately prior to the filing of the Chapter 11 petitions, the Company borrowed $300,000 from PRB Funding, LLC (PRB Funding) due on February 28, 2009. PRB Funding was formed by three members of our Board of Directors. The PRB Funding loan was secured by substantially all of the assets of PRB Energy and was repaid in 2009.

Post-Petition Debtor-in-Possession Financing

In April 2008, the Company obtained court approval of post-petition Debtor-in-Possession Financing (DIP Loan) from PRB Funding in the amount of $275,000. The PRB Funding DIP Loan accrued interest at 13% per annum, with all unpaid principal and accrued interest due upon the earlier of March 1, 2009 or the confirmation of the Plan.

In May 2008, the Company obtained court approval for $336,000 post-petition DIP Loan (the PRB Acquisition DIP Loan) from an unaffiliated entity. The PRB Acquisition DIP Loan accrued interest at 18% per annum, with all unpaid principal and accrued interest due upon the earliest of September 30, 2008, an event of default, or the confirmation of a plan of reorganization.

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Both DIP Loans were repaid in 2009.

Note 10 - Stockholders Equity

Common Stock and Warrants Issued

Upon emergence from bankruptcy, all 8,721,994 issued shares of PRB Energy s common stock were cancelled, and the following securities were issued in accordance with the Plan:

- 13.5 million shares of new common stock to WCOF, the principal pre-petition secured creditor;
- 1,419,339 million shares of new common stock, on a pro-rata basis, to holders of Class A-4 Claims (as defined in the Plan);
- 74,959 shares of new common stock, on a pro-rata basis, to holders of Class B-5 Claims (as defined in the Plan);
- Warrants, with an expiration date of December 31, 2013, to purchase 1,419,339 million shares of new common stock at an exercise price of $2.50 per share, on a pro-rata basis, to holders of Class A-4 Claims; and
- Warrants, with an expiration date of December 31, 2013, to purchase 74,959 shares of new common stock at an exercise price of $2.50 per share, on a pro-rata basis, to holders of Class B-5 Claims.

Through December 31, 2010 and 2009, respectively, cumulative activity with respect to warrants outstanding was as follows:

	2010	2009
Balance, beginning of year	1,494,298	375,000
Cancelled		(375,000)
Issued		1,494,298
Exercised		
Balance, end of year	1,494,298	1,494,298

Note 11 - Equity Compensation Plan

On June 3, 2009, the Board adopted the Black Raven Energy, Inc. Equity Compensation Plan (the Equity Compensation Plan) under which we may grant nonqualified stock options, stock appreciation rights, stock awards or other equity-based awards to certain of our employees, consultants, advisors and non-employee directors. The Board initially reserved 3,791,666 shares of common stock for issuance under the Equity Compensation Plan, and that number is adjusted annually to 25% of shares issued and outstanding on July 1. As of December 31, 2010, there are 4,165,241 shares of common stock authorized for issuance under the Equity Compensation Plan.

On July 1, 2009, the Company issued 1,060,000 stock options to employees of the Company under the Equity Compensation Plan. The options have an exercise price of $2.00 per share for a total estimated fair value as of issuance of $660,000 and vest ratably over three years. The Company issued the same employees an additional 172,500 stock options on September 16, 2009, which vested immediately. These options have an exercise price of $2.00 per share and a total estimated fair value as of issuance of $109,000. On December 8, 2009, the Company issued 100,000 options to two directors. The options have an exercise price of $2.00 per share and a total estimated fair value as of issuance of $64,000 and contractual lives of ten years..

On February 7, 2010, the Company issued 100,000 options to an officer of the Company. The options have an exercise price of $2.00 per share, a total estimated fair value as of issuance of $59,000 and vest over three years. On August 26, 2010, the Company issued 100,000 options to two directors. The options have an exercise price of $2.00 per share and a total estimated fair value as of issuance of $61,500. In October, 2010, the Company issued 150,000 options to employees of the Company. The options have an exercise price of $2.00 per share, a total estimated fair value as of issuance of $92,250 and vest over five years.

The Company recorded equity compensation expense during the years ended December 31, 2010 and 2009 totaling $303,000 and $283,000, respectively.

The following table summarizes activity for options:

	For the Year Ended December 31, 2010			**For the Year Ended December 31, 2009**		
	Number of Options	**Weighted Avg. Exercise Price**		**Number of Options**	**Weighted Avg. Exercise Price**	
Outstanding, beginning of year	1,332,500	$	2.00	551,750	$	5.23
Cancelled		$		(551,750)	$	5.23
Granted	350,000	$	2.00	1,332,500	$	2.00
Forfeitures	(35,000)	$	2.00		$	
Exercised		$			$	
Outstanding, end of year	1,647,500	$	2.00	1,332,500	$	2.00
Awards vested or expected to vest, end of year	1,421,667	$	2.00	999,375	$	2.00
Available for future grants, end of year	2,517,741			2,459,166		

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The weighted average remaining contractual life for the options outstanding at December 31, 2010 and 2009 respectively is 8.76 years and 9.56 years. The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model. Unrecognized compensation expense totaled $445,000 and $550,000 at December 31, 2010 and December 31, 2009, respectively.

The fair value of options was measured at the date of grant using the Black-Scholes option-pricing model. The fair values of options granted and employee stock purchase plan shares issued were estimated using the following weighted-average assumptions:

Assumption	December 31, 2010	December 31, 2009
Risk free interest rate (%)	0.56% - 1.48%	1.21% - 1.37%
Volatility factor of the expected market price of the Company s common stock	63.55% - 67.60%	60.15% - 62.92%
Contract life of the options (in years)	10	10
Expected dividend		

The Black-Scholes option valuation model was developed for use in estimating the fair value of traded options that have no vesting restrictions and are fully transferable. In addition, option valuation models incorporate highly subjective assumptions including the expected stock price volatility. The Company s stock options have characteristics significantly different from those of traded options and, as changes in the subjective input assumptions can materially affect the fair value estimate, it is management s opinion that the valuations as determined by the existing models are different from the value that the options would realize if traded in the market. The Company used an industry index to estimate the volatility factor of the stock.

Note 12 - Oil and Gas Activities

Costs Incurred in Oil and Gas Producing Activities

The Company has incurred the following costs, both capitalized and expensed, in respect to oil and gas property acquisition, exploration and development activities during the year ended December 31, 2010 and 2009, respectively:

(in thousands)	For the Years Ended December 31, 2010		2009	
Acquisitions				
Proved	$	36	$	28
Unproved		33		88
Exploration		12		8
Development costs		256		2
	$	337	$	126

The following table sets forth certain information regarding the results of operations for oil and gas producing activities for the years ended December 31, 2010 and 2009, respectively:

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(in thousands)	For the Years Ended December 31, 2010		2009	
Revenues, net	$	469	$	460
Production costs		(776)		(616)
Exploration		(12)		(8)
Depreciation, depletion and accretion (1)		(165)		(252)
	$	(484)	$	(416)

Note (1): Includes $143,000 and $232,000 of depreciation and depletion of well costs and $22,000 and $20,000 of accretion of asset retirement obligation for wells for the years ended December 31, 2010 and 2009 respectively.

Note 13 - Disclosures about Oil and Gas Producing Activities (Unaudited)

Recent SEC and FASB Guidance

In December 2008, the SEC published the final rules and interpretations updating its oil and gas reporting requirements. The Company adopted the rules effective December 31, 2009, and the rule changes, including those related to pricing and technology, are reflected in the Company s reserve estimates.

In January 2010, the FASB aligned ASC Topic 932, with the aforementioned SEC requirements. Please refer to the section entitled *Recently Issued Accounting Standard*s under Note 2 Summary of Significant Accounting Policies for additional discussion regarding both adoptions.

Oil and Gas Reserve Quantities

We engaged independent geological and petroleum engineering consultants MHA Petroleum Consultants, Inc. (MHA) in both 2010 and 2009 to estimate our natural gas reserves. The Company provided historical lease operating costs, production data and capital cost estimates to MHA. The Company reviewed the calculations and assumptions the consultants used to calculate the reserves. Please refer to the section entitled *Properties-Reserves* included in Part I, Item 2 of this report.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined, and the pricing that was used complies with the new SEC regulations (the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions). All of the proved reserves in 2010 and 2009 were located in Colorado and Wyoming.

The following table summarizes estimated proved reserves of gas in million cubic feet as of December 31, 2010 and 2009:

(in MMCf)	**2010**	**2009**
Proved developed and undeveloped:		
Proved developed, January 1	1,721	2,220
Proved undeveloped, January 1	7,428	2,129
Beginning of year, January 1	9,149	4,349
Revisions of previous estimates	(2,252)	4,949
Sales of reserves in place	(603)	
Discoveries	293	
Production	(124)	(149)
End of year, December 31	6,463	9,149
Proved developed, December 31	1,440	1,721
Proved undeveloped, December 31	5,023	7,428

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As of December 31, 2010 and December 31, 2009, 22.28% and 18.81% of the proved reserves were categorized as proved developed producing, respectively.

Standardized Measure of Discounted Future Net Cash Flows

The Company follows the guidelines prescribed in ASC Topic 932 for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The Company follows these guidelines that are summarized as follows:

- Future cash inflows, production and development costs are determined by applying oil and gas prices and costs, including overhead expense allocable, transportation, quality and basis differentials to the year-end quantities of oil and gas to be produced in the future;

- Future income taxes are estimated using current statutory income tax rates and estimated future statutory depletion;

- Future operating and development costs are based on estimates of expenditures in developing and producing proved oil and gas reserves in place at year-end, assuming continuity of year-end economic conditions;

- The resulting cash flows are reduced to present value using a 10% discount rate; and

- For 2010, the Company used a price of $3.81 per Mcf, as adjusted for energy content.

The following summarizes the standardized measure of future net cash flows relating to its proved gas reserves as of December 31, 2010 and 2009 as prescribed in ASC Topic 932:

(in thousands)		**2010**		**2009**
Future cash flows	$	24,596	$	26,922
Future production costs		(7,283)		(10,196)
Future development costs		(4,394)		(7,151)
Future income taxes				
Future net cash flows		12,919		9,575
Ten percent discount		(6,034)		(4,434)
Standardized measure of discounted future net cash flows	$	6,885	$	5,141

The following summarizes the changes in the standardized measure of discounted future net cash flows relating to its proved gas reserves as of December 31, 2010 and 2009 as prescribed in ASC Topic 932.

(in thousands)	**2010**	**2009**
Standardized measure beginning of year	$ 5,141	$ 6,262
Sales and transfers, net of production costs		
Net change in sales and transfer prices, net of production costs	5,818	(2,686)
Discoveries and extensions	634	
Changes in future development costs	1,469	118
Revisions of quantity estimates	(3,531)	(1,397)
Accretion of discount	499	626
Net changes in income taxes		
Purchases of reserves in place		
Sales of reserves in place	(156)	
Changes to production rates (timing) and other	(2,989)	(612)
Standardized measure of discounted future net cash flows	$ 6,885	$ 5,141