

**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION**

Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended **December 31, 2008**

OR

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

For the transition period from _____ to _____

Commission file no. **001-33457**

Pinnacle Gas Resources, Inc.

(Exact name of registrant as specified in its charter)

Delaware

*(State or other jurisdiction of
incorporation or organization)*

30-0182582

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

**1 E. Alger Street
Sheridan, Wyoming**

(Address of principal executive offices)

82801

(Zip code)

Registrant's telephone number, including area code: (307) 673-9710

Securities Registered Pursuant to Section 12(b) of the Exchange Act:

Title of Each Class

Name of Each Exchange on Which Registered

Common Stock

Nasdaq Global Market

Securities Registered Pursuant to Section 12(g) of the Exchange Act:

None

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

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

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

Large Accelerated Filer

Accelerated Filer

Non-Accelerated Filer
(Do not check if a smaller
reporting company)

Smaller Reporting Company

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

The aggregate market value of the registrant's common stock held by non-affiliates of the registrant was approximately \$68,107,043 as of June 30, 2008 (based on a closing price of \$3.60 per share and excluding 10,081,478 shares held by affiliates).

As of April 9, 2009, there were 29,188,009 shares of the registrant's common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement for the registrant's 2009 Annual Meeting of Stockholders are incorporated by reference in Part III of this Form 10-K. Such definitive proxy statement will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2008.

PINNACLE GAS RESOURCES, INC.

Index to Form 10-K

Cautionary Statement Concerning Forward-Looking Statements	i
Part I	
Items 1. and 2. Business and Properties	1
Item 1A. Risk Factors	25
Item 1B. Unresolved Staff Comments	40
Item 3. Legal Proceedings	40
Item 4. Submission of Matters to a Vote of Security Holders	41
Part II	
Item 5. Market for Registrant’s Common Stock, Related Stockholder Matters and Issuer Purchases of Equity Securities	42
Item 6. Selected Financial Data	44
Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations	46
Item 7A. Quantitative and Qualitative Disclosures About Market Risk	64
Item 8. Financial Statements and Supplementary Data	66
Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	102
Item 9A(T). Controls and Procedures	102
Item 9B. Other Information	103
Part III	
Item 10. Directors, Executive Officers and Corporate Governance	103
Item 11. Executive Compensation	103
Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	103
Item 13. Certain Relationships and Related Transactions, and Director Independence . . .	103
Item 14. Principal Accounting Fees and Services	103
Part IV	
Item 15. Exhibits and Financial Statement Schedules	104
Signatures	107

CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

We are including the following discussion to inform you of some of the risks and uncertainties that can affect our company and to take advantage of the “safe harbor” protection for forward-looking statements that applicable federal securities law affords. Various statements in this annual report on Form 10-K, including those that express a belief, expectation, or intention, as well as those that are not statements of historical fact, are forward-looking statements. These include statements relating to, among other matters:

- our financial position or operating results;
- projections and estimates concerning the timing and success of specific projects;
- our business strategy;
- our budget;
- the amount, nature and timing of capital expenditures;
- the drilling of wells;
- the development of natural gas and oil properties and commercial potential of these properties;
- the timing and amount of future production of natural gas and oil;
- our operating costs and other expenses;
- our estimated future net revenues from natural gas and oil reserves and the present value thereof;
- our cash flow and anticipated liquidity; and
- our other plans and objectives for future operations.

When we use the words “believe,” “intend,” “expect,” “may,” “should,” “anticipate,” “could,” “estimate,” “plan,” “predict,” “project,” their negatives, or other similar expressions, the statements which include those words are usually forward-looking statements. When we describe strategy that involves risks or uncertainties, we are making forward-looking statements. The forward-looking statements in this annual report on Form 10-K speak only as of the date of this report. We disclaim any obligation to update these statements unless required by securities law, and we caution you not to rely on them unduly. We have based these forward-looking statements on our current expectations and assumptions about future events. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. These risks, contingencies and uncertainties relate to, among other matters, the following:

- the availability of capital;
- fluctuations in the commodity prices for natural gas and crude oil and their related effects, including on cash flows and potential impairments of oil and gas properties;
- regional price differentials;
- the extent of our success in discovering, developing and producing reserves, including the risks inherent in exploration and development drilling, well completion and other development activities;
- the lack of liquidity of our equity securities;

- the substantial capital expenditures required for construction of pipelines and the drilling of wells and the related need to fund such capital requirements through commercial banks and/or public securities markets;
- engineering, mechanical or technological difficulties with operational equipment, in well completions and workovers, and in drilling new wells;
- the effects of government regulation and permitting and other legal requirements;
- the uncertainty inherent in estimating future natural gas and oil production or reserves;
- production variances from expectations;
- our ability to develop and replace reserves;
- operating hazards attendant to the natural gas and oil business, including down-hole drilling and completion risks that are generally not recoverable from third parties or insurance;
- potential mechanical failure or under-performance of significant wells;
- environmental-related problems;
- the availability and cost of materials and equipment;
- our dependence upon key personnel;
- our ability to find and retain skilled personnel;
- delays in anticipated start-up dates;
- disruptions of, capacity constraints in or other limitations on our or others' pipeline systems;
- land issues and the costs associated with perfecting title for natural gas rights in some of our properties;
- our ability to effectively market our production;
- competition from, and the strength and financial resources of, our competitors; and
- general economic conditions.

When you consider these forward-looking statements, you should keep in mind these factors and the other factors discussed under the "Risk Factors" section of this annual report on Form 10-K.

PART I

ITEMS 1 AND 2 *BUSINESS AND PROPERTIES*

General

Pinnacle Gas Resources, Inc. is an independent energy company engaged in the acquisition, exploration and development of domestic onshore natural gas reserves. We primarily focus our efforts on the development of coalbed methane, or CBM, properties located in the Rocky Mountain region, and we are a substantial holder of CBM acreage in the Powder River Basin. We have assembled a large, predominantly undeveloped CBM leasehold position, which we believe positions us for significant long-term growth in production and proved reserves. In addition, we own over 94% of the rights to develop conventional and unconventional oil and natural gas in zones below our existing CBM reserves. Substantially all of our undeveloped acreage as of December 31, 2008 was located in the northern end of the Powder River Basin in northeastern Wyoming and southern Montana.

As of December 31, 2008, we owned natural gas and oil leasehold interests in approximately 477,000 gross (332,000 net) acres, approximately 90% of which were undeveloped. At December 31, 2008, we had estimated net proved reserves of 27.7 Bcf, based on a year-end Colorado Interstate Gas, or CIG, index price of \$4.61 per Mcf. These net proved reserves were located on approximately 10% of our net acreage. Based on our drilling results to date, analysis of core samples and third-party results in adjacent areas, we believe that our remaining undeveloped CBM acreage has substantial commercial potential. None of our acreage or producing wells is associated with coal mining operations.

As of December 31, 2008, we owned interests in 663 gross (366 net) producing wells and operated 97% of these wells. During the year ended December 31, 2008, we drilled 117 gross (82 net) wells and produced an average of 10.6 MMcf per day net to our interest. We exited 2008 producing 10.1 MMcf per day net to our interest. During 2007, we drilled 87 gross (61 net) wells and produced an average of 9.3 MMcf per day net to our interest.

We had a total capital expenditure budget of \$30.1 million for 2008 and expected to drill 146 gross (110 net) wells during the period. However, due to low CIG index prices, the economic climate and limited capital resources, we reduced our 2008 capital expenditure budget resulting in actual 2008 capital expenditures of \$27.8 million. In connection with our reduced capital expenditure budget, we also reduced our drilling and completion targets for 2008. We curtailed substantially all new drilling in the fourth quarter of 2008, and we have shut-in a number of wells that are not economic at current natural gas price levels. If natural gas prices remain low, we expect to continue to operate with a reduced capital expenditure plan. Under our reduced capital expenditure plan, we would generally make such expenditures only as necessary to secure drilling permits in strategic areas, drill wells that secure leasehold positions and construct the necessary infrastructure to complete and hook-up wells that have already been drilled. Our capital expenditure budget for 2009 will be dependent upon CIG index prices, our cash flows and the availability of additional capital resources.

Our Powder River Basin and Green River Basin CBM Projects

During the period from our formation in June 2003 to December 31, 2008, we completed 777 gross (435 net) of the 817 gross (468 net) CBM wells we drilled in the Powder River and Green River Basins. As necessary infrastructure becomes available, we expect to complete the remaining gross wells drilled through December 31, 2008.

Powder River Basin

Our Powder River Basin properties are located in Wyoming and Montana. Our acreage position in the northern end of the Powder River Basin is generally contiguous, providing us with critical mass and the ability to execute large-scale development projects in our operating areas.

- *Wyoming.* Our principal Wyoming properties in the Powder River Basin are located in two distinct project areas: Recluse and Cabin Creek. As of December 31, 2008, we held approximately 120,000 gross (77,000 net) acres in the Powder River Basin in Wyoming for prospective CBM development and we operated over 98% of this acreage. As of December 31, 2008, we had 257 approved drilling permits for our Powder River Basin properties in Wyoming and we are in the process of applying for an additional 302 drilling permits which we expect to be approved in 2009 and 2010.
- *Montana.* Our Montana properties are located in four project areas: Kirby, Deer Creek, Bear Creek and Bradshaw. As of December 31, 2008, we held approximately 301,000 gross (220,000 net) acres in Montana for prospective CBM development and we operated 100% of this acreage. We have continued development in the Deer Creek and Kirby areas, and in 2008, we drilled 8 gross (5 net) wells in these areas. As of December 31, 2008, we had 32 approved drilling permits for our Montana properties and we are in the process of applying for an additional 213 drilling permits which we expect to be approved in 2009 and 2010. Of these additional permits, 90 are on fee and state land and 123 are on federal land.

Green River Basin

On April 20, 2006, we acquired undeveloped natural gas properties, including related interests and assets, located in the Green River Basin of Wyoming from Kennedy Oil for an aggregate purchase price of approximately \$27.0 million in cash. Our Green River Basin properties are located in the northeast area of Sweetwater County, Wyoming. As of December 31, 2008, our properties in the Green River Basin consisted of approximately 33,000 gross (32,000 net) undeveloped acres for prospective CBM development in the Fort Union Big Red Coal formation. As of December 31, 2008, we operated 100% of this acreage. As part of our initial acquisition, we also acquired 20 shut-in wells and 23 approved drilling permits and a 65% working interest in existing deep rights below the base of the Fort Union formation. As part of our initial pilot program, we have been successful in downspacing a section of our Green River Basin property from 160-acre spacing to 80-acre spacing, thus allowing us to more quickly dewater wells in this area and reach gas production. We have begun development of a water management system in the Green River Basin and are currently waiting on approval of our water management plan from the Wyoming Bureau of Land Management which we expect to receive in late 2009. It is more expensive to drill in the Green River Basin because of the increased depth of the wells, the increased cost of water management in the area and the need for additional infrastructure.

As of December 31, 2008, we had 14 approved drilling permits for our Green River Basin properties. We are in the process of applying for an additional 16 drilling permits which we expect to be approved in 2009 and 2010. In addition, we are in the process of applying for 34 drilling permits for conventional wells, which we expect to be approved through 2010. As of December 31, 2008, we had identified 170 drilling locations based on 160-acre spacing (or 340 drilling locations based on 80-acre spacing). As of December 31, 2008, we had no proved reserves established in our Green River Basin properties.

Summary of Our Powder River and Green River Basin Properties

	Producing Wells as of December 31, 2008		Producing Wells as of December 31, 2007		Estimated Potential Drilling Locations(1)	Estimated Total Net Acres(1)
	Gross	Net	Gross	Net		
Recluse	427	209	431	214	500	16,000
Cabin Creek	156	104	89	53	540	37,000
Kirby(3)	23	15	114	75	1,465	44,000
Deer Creek(3)	57	38	0	0	520	41,000
Bear Creek	0	0	0	0	885	64,000
Bradshaw	0	0	0	0	970	71,000
Green River Basin	0	0	0	0	170	32,000
Other(2)	0	0	0	0	150	27,000
Total	<u>663</u>	<u>366</u>	<u>634</u>	<u>342</u>	<u>5,200</u>	<u>332,000</u>

(1) Estimated as of December 31, 2008.

(2) Includes approximately 3,000 net acres in the Big Horn Basin, Big Horn County, Wyoming.

(3) In 2008, certain wells in the Kirby area were reassigned to the Deer Creek area. For the year ended December 31, 2008, the total wells for the two areas combined declined from 114 gross (75 net) wells to 80 gross (53 net) wells.

Our History

We were formed as a Delaware corporation in June 2003 by funds affiliated with DLJ Merchant Banking III, Inc., which we refer to collectively as DLJ Merchant Banking, and subsidiaries of Carrizo Oil & Gas, Inc., or Carrizo, and U.S. Energy Corporation, or U.S. Energy. Carrizo and U.S. Energy contributed oil and gas reserves and leasehold interests in approximately 81,000 gross (40,000 net) acres in exchange for shares of our common stock and options to purchase shares of our common stock. DLJ Merchant Banking completed several cash investments in us in exchange for shares of our common stock, Series A Redeemable Preferred Stock, and warrants to purchase additional shares of our common stock, and has been instrumental in providing capital to drive our growth. As of December 31, 2008, DLJ Merchant Banking and Carrizo owned approximately 32.9% and 8.3% of our outstanding common stock, respectively.

In April 2006, we completed a private offering of 12,835,230 shares of our common stock to qualified institutional buyers, non-U.S. persons and accredited investors. Immediately prior to the initial closing of our private placement, DLJ Merchant Banking exchanged all of their warrants for 6,894,380 shares of common stock in a tax-free reorganization and each of Carrizo and U.S. Energy entered into a cashless exercise of all of their options for 584,102 shares of common stock, in each case based on the private placement price of \$11.00 per share. Following the initial closing of our private placement, we redeemed all of the outstanding shares of Series A Redeemable Preferred Stock held by DLJ Merchant Banking with a portion of the proceeds we received in the private placement. In addition, following the final closing of our private placement, we used a portion of the proceeds we received in the private placement to repurchase an aggregate of 1,587,598 shares of common stock from DLJ Merchant Banking at a price per share equal to the private placement price of \$11.00 per share less the initial purchaser's discount and placement fee. On September 22, 2006, DLJ Merchant Banking purchased all of the 2,459,102 shares of our common stock held by U.S. Energy and its affiliates in a private transaction.

In May 2007, we completed an initial public offering of 3,750,000 shares of our common stock at a public offering price of \$9.00 per share.

In addition to the initial contribution of leasehold interests to us by U.S. Energy and Carrizo, during the period from our formation in June 2003 to December 31, 2008, we acquired leasehold interests covering approximately 396,000 gross (292,000 net) acres, primarily from three significant acquisitions.

- In June 2003, we acquired approximately 57,000 gross (22,000 net) acres along with 210 gross (96 net) producing wells and shut-in wells in Wyoming from Gastar Exploration, Ltd. and certain of its affiliates.
- In March 2005, we acquired approximately 223,000 gross (196,000 net) undeveloped acres for prospective CBM development in Montana and Wyoming from a subsidiary of Marathon Oil Corporation.
- In April 2006, we acquired approximately 30,000 gross (29,000 net) undeveloped acres in the Green River Basin in Wyoming.

Please see the information under the heading “Our Powder River Basin and Green River Basin CBM Projects—Green River Basin” in this annual report.

Capital Expenditure Plan

We had a total capital expenditure budget of \$30.1 million for 2008 and expected to drill 146 gross (110 net) wells during that period. However, due to low CIG index prices, the economic climate and limited capital resources, we reduced our 2008 capital expenditure budget resulting in actual 2008 capital expenditures of \$27.8 million. In connection with our reduced capital expenditure budget, we also reduced our drilling and completion targets for 2008. During the year ended December 31, 2008, we drilled 117 gross (82) net wells. We curtailed substantially all new drilling in the fourth quarter of 2008, and we have shut-in a number of wells that are not economic at current natural gas price levels. If natural gas prices remain low, we expect to continue to operate with a reduced capital expenditure plan. Under our reduced capital expenditure plan, we would generally make such expenditures only as necessary to secure drilling permits in strategic areas, drill wells that secure leasehold positions and construct the necessary infrastructure to complete and hook-up wells that have already been drilled. The CIG index price has been extremely volatile during 2007 and 2008 and at times reached unusually low levels. For instance, the CIG monthly index price per Mcf was \$1.78, \$3.41, \$2.78 and \$4.63 for delivery in September, October, November and December of 2008, respectively. If prices remain low, our cash flows from operations will decrease and the borrowing base and borrowing availability under our credit facility could be further reduced. If we do not have sufficient cash flows and cannot obtain capital through our credit facility or otherwise, our ability to execute our development and acquisition plans, replace our reserves and maintain production levels could be greatly limited. If natural gas prices do not improve, we will consider alternatives to increase liquidity, including asset sales and issuances of equity. Our capital expenditure budget for 2009 will be dependent upon CIG index prices, our cash flows and the availability of additional capital resources. For a discussion of our credit facility and other matters that may limit our ability to execute our 2009 capital expenditure plan, please see “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity—Credit Facility.”

We are actively marketing certain assets to raise additional capital and are also reviewing alternatives for raising additional capital through equity and debt financing, capital restructuring and possible mergers. We sold our high pressure gas gathering system in our Cabin Creek project area in Wyoming and our remaining interest in the Arvada project area in Wyoming in April 2009. Although we are pursuing various alternatives to provide additional liquidity, there is no assurance of the likelihood or timing of any of these transactions.

Overview of the CBM Industry and the Powder River Basin

CBM is natural gas that is trapped within buried coal and is stored, or adsorbed, onto the internal surfaces of the coal. Geologists have long known that coal was the source for natural gas found in many conventional accumulations, but coalbeds were not targeted for production due to high water content and minimal natural gas production. Following a West Virginia mine explosion in 1968, the U.S. Bureau of Mines began to examine ways of removing methane from coal prior to mining. The Bureau of Mines demonstrated that CBM can be produced when large volumes of water are pumped from a coal seam. In a process known as dewatering or depressuring, a submersible pump is set below the coal seam, and the water column is pumped down, reducing the pressure in the coals. As pressure within the coalbed formation is reduced, CBM is released through a process called desorption. CBM then moves into naturally occurring cracks, or cleats, in the coal, and then to the production wells. Cleats are natural fractures which have formed in the coals, usually as a result of the coalification process and geological stresses. Because the cleats are generally filled with water, the static water level above the coal must be reduced, which then lowers the reservoir pressure allowing desorption to occur. Thus, unlike producing from a conventional natural gas reservoir, reservoir pressure in a coalbed formation must generally be reduced to allow for production of CBM. Because of the necessity to remove water and reduce the pressure within the coal seam, CBM, unlike conventional hydrocarbons, often will not show immediately on initial production testing. Coalbed formations typically require extensive dewatering and depressuring before desorption can occur and the methane begins to flow at commercial rates.

In the past 20 years, CBM in the United States has evolved into a major component of the United States natural gas production. According to the National Energy Technology Laboratory, CBM provides approximately 8% of daily natural gas production in the United States. The Rocky Mountain region, due to its immense coal reserve base, is a significant source of United States CBM production, and there are more than 17,000 CBM wells in the Powder River Basin, according to the U.S. Department of Energy. The primary CBM basins include the San Juan, Green River, Raton, Powder River and Uinta Basins in the western United States.

Future CBM production is expected to increase substantially due to the economic viability of the resources and the tremendous reserve potential of the numerous, virtually undeveloped U.S. coal basins. Within the Rocky Mountain region, the Powder River Basin has become a major CBM producing basin. According to the U.S. Department of Energy 2002 Powder Basin Coalbed Methane Development and Produced Water Management Study, the Montana portion of the Powder River Basin is estimated to have substantial recoverable reserves. According to the Wyoming Oil and Gas Conservation Commission, approximately 1.4 Bcf of CBM has been produced from the Powder River Basin per day.

The Powder River Basin is an asymmetrical structure and sedimentary basin bounded by the Bighorn and Black Hills uplift and the Casper Arch. The Paleocene Fort Union formation crops out along the basin margin and is overlain by the Eocene Wasatch formation in the central and western part of the basin. The Wasatch and Fort Union formations contain numerous coalbeds, some of which approach 250 feet in total thickness. The Fort Union formation is divided, in ascending stratigraphic order, into the Tullock, Lebo, and Tongue River members, with the majority of coal and CBM production being produced from the Tongue River member.

The majority of Powder River Basin CBM reserves are found in the Fort Union formation. Extensive drilling in the Fort Union formation (over 25,000 drilled well bores) has provided supporting data indicating that this formation contains numerous coalbeds which are generally continuous, extremely permeable and relatively shallow (less than 1,000 feet deep) and low in rank (geologic maturity) compared to other coals in the Rocky Mountains.

Drilling and Production

CBM wells in the Powder River Basin are drilled with small truck mounted water well rigs and are drilled and completed using two basic completion techniques. The first and most common drilling technique is open hole completion. The well is drilled to the top of the target coal seam and production casing is set and cemented back to the surface. The coal seam is then drilled out and under-reamed to open up more coal face to production. The second completion technique is to drill through the base of the target coal and then set casing and cement to the surface. The well is then completed by perforating the casing at the target coal. In both completion techniques, the borehole and coal face are then cleaned out and flushed by pumping approximately 600 barrels of formation water at high rates into the coal face. Once the well is completed, a submersible pump is run into the well on production tubing to pump the water from the coal seam. After the coal is depressurized, gas flows up the casing to the wellhead. At the wellhead, the gas and water are metered. The gas then flows to a central compressor station where it is compressed into a high-pressure pipeline. The water is sent through an underground pipeline for beneficial use or disposal. CBM production must be continuous to ensure a constant low-pressure gas flow and to sustain a commercially viable operation.

We have developed specific drilling, cementing and completion technology that we have adapted to the rank, depth and thickness of the coals found in all of our operating areas. Our drilling, completion and production practices utilize technological advances in cementing, multiple zone completions and programmable submersible pumps. We have developed drilling and cementing techniques that minimize the damage to coal zones, preserve the potential of coals behind pipe and reduce cementing costs. Multiple zone completions allow for the successful perforation of multiple zones which reduces costs and gives us the ability to sustain production from coals less than ten feet in thickness. Programmable submersible pumps and telemetry allow us to implement aggressive production management programs on our wells and projects.

Conventional gas wells are typically 8,000 to 20,000 feet deep and initially produce large volumes of gas relative to water. Natural gas normally does not require assistance to move to the surface, and over time, gas production declines and water production may increase. In contrast, CBM wells generally range from 300 to 4,000 feet. In the early stages of CBM production, large quantities of water and low quantities of gas are produced. Water production is initiated to lower the downhole pressure which allows the methane to release from the coal. The water volumes eventually decline and gas quantities begin to rise. In most cases, assistance to bring the gas to surface is not needed for the final period of production.

Water Production and Management

Water production and disposal is a key issue in CBM development. CBM-produced water in Wyoming and Montana must have a beneficial use, which is generally defined as using the water for agricultural, irrigation, commercial, domestic, industrial, municipal, mining, hydropower production, recreational, stockwatering and fisheries, wildlife and wetlands maintenance purposes or dust suppression. Currently, the management of CBM-produced water depends on the quality of the produced water. The water produced in CBM operations can vary from very high quality (meeting state and federal drinking standards) to very low quality (having a very high concentration of dissolved solids, making it unsuitable for reuse). Testing of the produced water determines the disposal method.

Produced water is handled by utilizing one or several of the following approved methods:

- surface discharge;
- containment in reservoirs;
- irrigation of surface lands;
- injection to shallow sand formations;
- enhanced evaporation systems;
- treatment through ion exchange or reverse osmosis; and/or
- sub-surface irrigation.

We include water gathering and water disposal costs in our hook-up, infrastructure and water management cost estimate of between \$62,000 and \$109,000 per well depending on the location and the number of wells drilled on an 80-acre spacing unit.

We have a water treatment agreement with EMIT Water Discharge Technology, LLC for our Cabin Creek project. Pursuant to the agreement, EMIT installed and operates treatment facilities necessary to treat a maximum daily quantity of water in exchange for a fixed daily fee and a variable fee per barrel of treated water that varies with the sodium content of the water. The rate is subject to adjustment annually for inflation. The agreement has an initial term of three years from July 2007, the first date upon which EMIT was ready and able to treat water, and continues on a month-to-month basis thereafter unless terminated by either party upon 90 days' written notice. Prior to the end of the initial term, we may extend the term by another three years upon payment of a renewal fee.

Recovery Characteristics

The primary variables that affect recovery of CBM are coal thickness, gas content and permeability. Coal thickness refers to the actual thickness of the coal layer and is used to estimate how many tons of coal underlie a section of land. The estimate of the number of tons per section is multiplied by the estimated gas content of such lands to estimate the gas in place for the section. Gas content in coal is measured in terms of standard cubic feet per ton. Sufficient coal permeability is a prerequisite for economic gas flow rates because gas and water must be able to flow to the wellbore. Most gas and water flow through the cleats and other fractures in the coal. Cleat spacing is influenced by a variety of factors and greatly affects permeability.

Powder River Basin CBM Production Overview

The Powder River Basin is located in northeastern Wyoming and southern Montana. The Powder River Basin is rich in natural resources with significant reserves of oil and gas as well as some of the world's thickest coal seams. The Powder River Basin holds the distinction of being the leading

coal-producing area in the United States, and in recent years, has become one of the most active areas for oil and gas drilling.

On 80-acre spacing, we had approximately 5,030 drilling locations in the Powder River Basin as of December 31, 2008. We target an average of three coal seams per location and have up to five coal seams that we believe are capable of commercial production. We expect that many of our wells will be completed to more than one coal seam, and thus we may drill less than three wells per location. The coal seams that we target are part of the Fort Union formation and include the Canyon, Cook, Wall, Pawnee and Flowers-Goodale (the Roberts equivalent) coals, which are found at depths ranging from 200 to 1,500 feet and are each approximately 15 to 60 feet thick.

Our wells generally reach total depth in one day and cost between \$95,000 and \$122,000 per well to drill and complete, depending on location, coal zones perforated and depth. Hook-up, infrastructure and water management costs are between \$62,000 and \$71,000 per well in the Powder River Basin. Powder River CBM wells are drilled with small truck mounted water well rigs and are completed as either single or multiple zone producers. In a single coal completion, we top set the casing in the first foot of coal and complete the well by under-reaming the coal with a 12-inch diameter tool. In a multiple zone completion, we typically top set and under-ream the deepest coal seam and perforate the upper coal seams sequentially. Our general production profile for a CBM well shows production of water for 30 to 90 days prior to initial gas production. The lowering of the static water level reduces the coal formation pressure and allows the gas to desorb from the coal and migrate to the well bore. Gas production typically inclines steeply for an average of nine months, peaking at an average of over 100 Mcf per day. A period of relatively flat production at peak continues for three to four months and then declines at an annual rate of approximately 35% over a five to seven year period. Produced water is handled by discharging it through one or more of several approved methods.

Our CBM wells in the Powder River Basin have all been drilled and cemented in anticipation of completing more than one coal seam per well bore. In our project areas, depending on the thickness of and horizontal separation between coal seams, we generally complete several coals in one well upon initial hook-up. Coal seams thicker than 25 feet are initially drilled as stand alone wells. Coal seams with less than 100 feet of vertical separation are completed simultaneously at initial hook-up. Our development activities include an active program to sequentially complete upper coal seams in wells that are producing from a single coal seam since being initially drilled and completed. We presently have over 150 wells that have been identified in the Recluse area for further completions in upper coals. Our completion strategy generally is to wait for the lower coal zones' measured pressure to reach or equal the measured pressure of the upper zones. Once the measured pressures are determined to be equal, the upper zones are perforated and completed. Sequential completion of upper coal seams typically costs \$12,000 per coal seam. We expect that multiple zone completions can increase the economic life of a well, increase previously unbooked behind pipe reserves from several thinner coal seams and enhance our rate of return.

Green River Basin CBM Production Overview

The Green River Basin is primarily located in southwestern Wyoming, and our assets are located in the eastern half of the Wyoming portion of the Green River Basin. According to the U.S. Department of Energy 2004 Coal Bed Methane Primer, the Green River Basin has significant potential CBM reserves in place. The Green River Basin is an increasingly active basin for natural gas and CBM exploration and drilling. An Environmental Impact Statement, or EIS, is currently being prepared by the Wyoming Bureau of Land Management for the drilling and development of up to approximately 9,000 natural gas wells, including up to 500 CBM wells, on a 1.1 million acre project area. Our Green River Basin acreage position is offset by multiple fields producing from conventional reservoirs in the Lance, Lewis and Almond sandstones. In 2008, there were approximately 31 CBM projects in the eastern half of the Green River Basin with a total of 176 CBM wells drilled. These

projects are being developed by approximately 13 operators targeting coals in the Mesaverde, Fort Union and Wasatch formations.

The Fort Union Big Red Coal, which we are targeting, is found at depths between 2,500 to 6,500 feet. The Fort Union coals, including the Big Red Coal, aggregate approximately 100 feet in thickness. The Big Red Coal accounts for up to 50 feet of the thickness. The Fort Union coals on our acreage have excellent permeability and gas saturation of generally 200 to 400 scf per ton of coal. In addition to the Big Red Coal, CBM potential exists in other coals of the Fort Union formation and in coals in the Wasatch and Mesaverde formations.

We anticipate developing the Green River Basin CBM reserves primarily on 160-acre spacing. The 14 gross (14 net) wells drilled as of December 31, 2008 on the acreage have generally reached total depth in five days. We estimate that future wells will cost an average of \$787,000 to drill, complete and hook up. We intend to complete the wells by under-reaming the coal or drilling through the coal and perforating the coal formation. Our estimated production profile assumes little gas production for three to five months as the well is dewatered and the formation pressure lowered, a steep incline in production for the following 12 months, peak production for 18 to 24 months and then a slow decline in production of approximately 10% per year over a 20 to 25 year period. We estimate the standard reserve life of a well in the Green River Basin will be approximately 25 years.

Operations

CBM Development, Projects and Operations

Our properties in the Powder River Basin are primarily located in northeastern Wyoming and southern Montana and are generally contiguous, providing us with critical mass and the ability to execute large scale development projects in our operating areas. As of December 31, 2008, we owned leasehold interests in approximately 421,000 gross (297,000 net) acres in the Powder River Basin, approximately 99% of which we operated. As of December 31, 2008, we also owned leasehold interests in 33,000 gross (32,000 net) acres in the Green River Basin in Wyoming.

Most of our development drilling is in areas of known natural gas reserves and involves much lower risk than the exploratory type of drilling that is required when searching for new natural gas reserves. During the period from our formation in June 2003 to December 31, 2008, we completed 777 gross (435 net) of the 817 gross (468 net) CBM wells we drilled in the Powder River and Green River Basins. As necessary infrastructure becomes available, we expect to complete the remaining gross wells drilled through December 31, 2008. During the year ended December 31, 2008, we drilled 117 gross (82 net) wells and connected 110 gross (77 net) wells to our low-pressure gathering system. During the year ended December 31, 2007, we drilled 87 gross (61 net) wells and connected 108 gross (73 net) wells to our low-pressure gathering system. At December 31, 2008, we were producing natural gas from approximately 663 gross (366 net) CBM wells at a net rate of 10.6 MMcf per day measured at the wellhead. In response to lower CIG index prices, the state of the economy in general and limited capital resources, we reduced our 2008 capital expenditure budget from \$30.1 million to \$27.8 million. We also reduced our drilling and completion targets for 2008 from approximately 146 gross (110 net) to approximately 117 gross (82 net) wells. Our revised 2008 capital expenditure budget was used to drill and complete wells in 2008, to construct gas and water infrastructure, to fund plans of development costs for future wells, to fund undeveloped leasehold acquisition costs carried over from 2007, to recompleat certain wells, and to fund infrastructure and completion costs related to such wells drilled in 2007. If natural gas prices remain low, we expect to continue to operate with a reduced capital expenditure plan that allows us to secure drilling permits in strategic areas, drill wells that secure leasehold positions and construct the necessary infrastructure to complete and hook-up wells that have already been drilled. Our capital expenditure budget for 2009 will be dependent upon CIG index prices, our cash flow and the availability of additional capital resources.

We have identified approximately 5,200 CBM drilling locations on our existing acreage, primarily on 80-acre well spacing, targeting an average of three coal seams per location. We target the Canyon, Cook, Wall, Pawnee and Flowers-Goodale (the Roberts equivalent) coal seams in the Powder River Basin, which are found at depths ranging from 200 to 1,500 feet, and the Fort Union Big Red Coal in the Green River Basin, which is found at depths ranging from 2,500 to 6,500 feet. Each coal seam is approximately 15 to 60 feet thick. As of December 31, 2008 and based on a year-end CIG index price of \$4.61 per Mcf, Netherland, Sewell & Associates, Inc., or NSAI, had identified over 5,300 economic completions, consisting of 881 proved, 507 probable and 3,938 possible, across our approximately 5,200 drilling locations, assuming one coal seam per well. We expect that many of our wells will be completed to more than one coal seam.

Wyoming—Powder River Basin

Our principal Wyoming properties in the Powder River Basin are located in two distinct project areas: Recluse and Cabin Creek. As of December 31, 2008, we held approximately 120,000 gross (77,000 net) acres in the Powder River Basin in Wyoming for prospective CBM development and we operated over 98% of this acreage.

Approximately 54% of our gross acreage in the Powder River Basin in Wyoming is on U.S. federal land, and is subject to additional regulations not applicable to state or fee leases. Permitting new wells in Wyoming on federal land involves submitting a plan of development, or POD, to the Wyoming division of the United States Bureau of Land Management, or Wyoming BLM, and is subject to an environmental assessment and a review period. Typically, it takes three to six months to complete the permitting process and receive approval from the Wyoming BLM. Permitting new wells on state and fee land requires approval from the Wyoming Oil and Gas Conservation Commission and the approval process typically takes 30 to 60 days. Please see the information under the heading “Regulations—Permitting Issues for Federal Lands” in this section of this annual report for further information.

As of December 31, 2008, we had 257 approved drilling permits for our Wyoming properties in the Powder River Basin and we are in the process of applying for an additional 302 drilling permits which we expect to be approved in 2009 and 2010.

- *Recluse*—Recluse is located on the northern end of the Gillette Fairway, where a majority of Powder River Basin CBM has been produced to date. As of December 31, 2008, we held approximately 34,000 gross (16,000 net) acres in the Recluse area, of which approximately 34% were developed. As of December 31, 2008, we operated approximately 99% of these properties. As of December 31, 2008, we were producing approximately 11.8 gross (4.5 net) MMcf per day from approximately 427 gross (209 net) wells in this area. During the year ended December 31, 2008, we drilled 9 gross (3 net) wells. Our gas is gathered in over 200 miles of low-pressure gathering systems which we installed and own. As of December 31, 2008, we had approximately 7.2 Bcf of net proved reserves in the Recluse area based on a CIG index price of \$4.61 per Mcf. We have identified approximately 500 potential drilling locations in Recluse and we are currently evaluating drilling plans for 2009 in light of the current economic and gas pricing environment.
- *Cabin Creek*—Our Cabin Creek project is located on the northern border of Wyoming adjacent to St. Mary’s Hanging Woman project to the west. As of December 31, 2008, we held approximately 55,000 gross (37,000 net) acres in Cabin Creek, of which approximately 25% were developed. As of December 31, 2008, we operated approximately 81% of these properties. We have a non-operating working interest in 32 wells operated by St. Mary Land and Exploration Company which are covered by a joint operating agreement. As of December 31, 2008, we participated in wells that were producing approximately 8.2 gross (3.6 net) MMcf per day from approximately 156 gross (104 net) wells in this area. During the year ended December 31, 2008, we drilled 97 gross (71 net) wells. As of December 31, 2008, we had approximately 12.4 Bcf of

net proved reserves in the Cabin Creek area based on a CIG index price of \$4.61 per Mcf. We have identified approximately 540 potential drilling locations and are currently evaluating drilling plans for 2009 in light of the current economic and gas pricing environment.

- *Other*—As of December 31, 2008, we held approximately 31,000 gross (24,000 net) acres in three non-core project areas in Wyoming, all of which are undeveloped. As of December 31, 2008, we operated approximately 80 gross (58 net) wells in these areas and had approximately 0.3 Bcf of net proved reserves based on a CIG index price of \$4.61 per Mcf.

Montana—Powder River Basin

Our Powder River Basin properties in Montana are located in four project areas: Kirby, Deer Creek, Bear Creek and Bradshaw. As of December 31, 2008, we held approximately 301,000 gross (220,000 net) acres in Montana for prospective CBM development and we operated 100% of this acreage. In 2008, our primary focus was the construction of water management infrastructure in the Kirby and Deer Creek areas. In addition, we drilled 8 gross (5 net) wells in these areas.

Because CBM development in Montana is still in its early stages, the permitting process is not as streamlined in Montana as it is in Wyoming. Permitting new wells in Montana on federal land involves submitting a plan of development, or POD, which typically covers approximately 30 to 100 80-acre locations, to the Montana division of the United States Bureau of Land Management, or Montana BLM, and is subject to an environmental evaluation under the National Environmental Policy Act and a review period. Permitting new wells on state and fee land involves submitting a POD, which typically covers 200 to 300 wells, to the Montana Oil and Gas Conservation Commission, and is also subject to an environmental evaluation under the National Environmental Policy Act and a review period. An injunction which prohibited the Montana BLM from approving any CBM drilling permits in certain federal lands in the Montana portion of the Powder River Basin was lifted in December 2008. The primary lease term of federal acreage covered by the injunction was suspended during the time period that the injunction was in effect. We estimate the suspension will add an additional three to five years to the primary term of all affected federal leases. Fee and state permits were unaffected by the injunction. Approximately 67% of our gross acreage in Montana is on U.S. federal land. Prior to the issuance of the injunction, the permit approval process for federal lands typically took about a year. The permit approval process for fee and state lands typically takes three to six months. See “—Regulations—Permitting Issues for Federal Lands” for further discussion of the Montana federal permitting process and injunction.

As of December 31, 2008, we had 32 approved drilling permits for our Montana properties. We are in the process of applying for an additional 213 drilling permits, 123 of which are on federal lands and 90 of which are on state or fee lands. We expect these permits to be approved in 2009 and 2010. We are currently evaluating drilling plans for 2009 in light of the current economic and gas pricing environment.

- *Kirby*—Kirby was acquired at the time of our initial formation in 2003. As of December 31, 2008, we held approximately 97,000 gross (44,000 net) acres in our Kirby project area, of which approximately 2% were developed. Kirby is located adjacent to and just north of Fidelity Exploration and Development Company’s project area, which is north of J. M. Huber’s project area in Wyoming. As of December 31, 2008, we were producing approximately 1.4 gross (0.6 net) MMcf per day from approximately 23 gross (15 net) producing wells in this area. During the year ended December 31, 2008, we drilled 6 gross (3 net) wells in the Kirby area at depths between 500 and 1,200 feet in the Wall and Flowers-Goodale coals. We have commercial gas production from Kirby and transport our Kirby gas production through the Bitter Creek Pipeline, which became operational in late August 2006. We plan to target up to six distinct coal seams in the Kirby area.

As of December 31, 2008, we had approximately 4.0 Bcf of net proved reserves in Kirby based on a CIG index price of \$4.61 per Mcf. We have identified approximately 1,465 potential drilling locations in Kirby.

- *Deer Creek*—As of December 31, 2008, we held approximately 49,000 gross (41,000 net) acres in our Deer Creek project area, of which approximately 9% were developed. Our Deer Creek project area is located adjacent to St. Mary's Hanging Woman project to the south and Fidelity's CX Ranch Field to the west. Extensive drilling activity has occurred in both areas to date.

We acquired this acreage as part of the acquisition of properties from Marathon Oil Corp. in March 2005 and we operate 100% of the acreage. We began development in 2005 in the Dietz POD which is located in the Deer Creek area just to the southeast of Kirby. As of December 31, 2008, we were producing approximately 3.0 gross (1.4 net) MMcf per day from approximately 57 gross (38 net) wells in this area. During the year ended December 31, 2008, we drilled 2 gross (2 net) wells in the Deer Creek area at depths between 200 and 1,000 feet and targeted the Anderson, Canyon, Cook, and Wall coal seams. We transport our Deer Creek gas production through the Bitter Creek Pipeline.

As of December 31, 2008, we had 3.8 Bcf of proved reserves in Deer Creek. We have identified approximately 520 potential drilling locations. Approximately 79% of our gross acreage in Deer Creek is on U.S. federal land.

- *Bear Creek*—As of December 31, 2008, we held approximately 76,000 gross (64,000 net) acres in our Bear Creek project area, all of which were undeveloped. Our Bear Creek project area is located adjacent to and just north of our Cabin Creek project area in Wyoming and northeast of St. Mary's Hanging Woman project. We operate all of our acreage in Bear Creek, which was acquired from Marathon Oil Corp. in March 2005.

As of December 31, 2008, we had no proved reserves in Bear Creek. We have identified approximately 885 potential drilling locations targeting eight distinct coal seams that appear to have significant gas potential based on recent core samples. Approximately 87% of our gross acreage in Bear Creek is on U.S. federal land, and as of December 31, 2008, we had no drilling permits for Bear Creek.

- *Bradshaw*—Our Bradshaw project area is located to the northeast of our Cabin Creek project area in Wyoming. As of December 31, 2008, we held approximately 79,000 gross (71,000 net) acres in Bradshaw, all of which were undeveloped. As of December 31, 2008, we operated all of the acreage.

As of December 31, 2008, we had no proved reserves in Bradshaw. We have identified approximately 970 potential drilling locations targeting eight distinct coal seams. Approximately 78% of our gross acreage in Bradshaw is on U.S. federal land, and as of December 31, 2008, we had no drilling permits for Bradshaw.

Wyoming—Green River Basin

On April 20, 2006, we acquired undeveloped natural gas properties, including related interests and assets, located in the Green River Basin of Wyoming from Kennedy Oil. The initial acquisition included approximately 30,000 gross (29,000 net) undeveloped acres for prospective CBM development in the Fort Union Big Red Coal formation. As of December 31, 2008, we owned 33,000 gross (32,000 net) undeveloped acres and we operated 100% of this acreage. As part of the acquisition, we also acquired 20 shut-in wells and 23 approved drilling permits and a 65% working interest in existing deep rights below the base of the Fort Union formation. As of December 31, 2008, we had drilled 14 gross (14 net) wells. As of December 31, 2008, we had 14 approved permits for our Green River Basin properties. We are in the process of applying for an additional 16 drilling permits which we

expect to be approved in 2009 and 2010. In addition, we are in the process of applying for 34 drilling permits for conventional wells which we expect to be approved through 2010. As of December 31, 2008, we had identified 170 drilling locations based on 160-acre spacing (or 340 drilling locations based on 80-acre spacing). As of December 31, 2008, we had no proved reserves in the Green River Basin.

Exploration & Production Activities

Producing Wells and Acreage

The following table sets forth certain information regarding our ownership of productive wells and total acreage as of December 31, 2006, 2007 and 2008. For purposes of this table, productive wells are wells producing gas or dewatering.

	Productive Wells		Approximate Leasehold Acreage					
			Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
December 31, 2006	529	281	26,160	17,400	427,840	290,600	454,000	308,000
December 31, 2007	634	342	33,120	22,200	460,880	293,800	494,000	316,000
December 31, 2008(1)	663	366	47,000	31,800	430,000	300,200	477,000	332,000

- (1) Gross undeveloped and total acreage decreased from December 31, 2007 to December 31, 2008 due to the expiration of acreage in our Kirby project area where we had a 50% working interest. Net undeveloped and total acreage increased from December 31, 2007 to December 31, 2008 due to the acquisition of other acreage where we have a 100% working interest.

Lease Expirations

	Expiring Acres 2009(1)		Held by Production		Suspended(2)	
	Gross	Net	Gross	Net	Gross	Net
Wyoming						
Recluse	502	342	30,021	15,239	0	0
Cabin Creek	77	7	18,717	15,863	0	0
Green River Basin	0	0	6,761	6,537	4,841	4,361
Montana						
Bear Creek	1,275	628	844	769	66,020	57,163
Deer Creek	480	108	5,100	3,955	38,817	32,553
Bradshaw	5,368	3,959	0	0	61,327	60,662
Kirby	1,969	833	22,230	12,375	34,651	17,324
Totals	<u>9,671</u>	<u>5,877</u>	<u>83,673</u>	<u>54,738</u>	<u>205,656</u>	<u>172,063</u>

- (1) Leases expiring in 2010 based on lease expirations represent approximately 16,663 gross (10,794 net) acres. The combined expirations of leased acreage for 2009 and 2010 account for 6% of our gross and 5% of our net acreage currently in place. Failure to pay shut-in and delay rental payments could result in further expiration of leased acreage. We are evaluating our expiring leases for 2009 and 2010 to determine whether we should pursue extensions or release the acreage. Expiration of leases in future years could also result in additional impairments in unevaluated properties.
- (2) In April and June 2005, the U.S. Bureau of Land Management in Miles City, Montana issued suspensions of operations for the majority of our federal leases in Montana. The suspensions were issued based upon a court order issued on April 5, 2005 by the U.S. District Court of Montana

that required the BLM to complete a Supplemental Environmental Impact Statement (SEIS) to address phased development of coal bed natural gas. The U.S. Ninth Circuit Court of Appeals also issued an order on May 31, 2005 which enjoined the BLM from approving coal bed natural gas production projects in the Powder River Basin of Montana. Both of these actions placed limitations on lease development until completion of the SEIS.

The 2005 injunction was lifted by the Ninth Circuit Court of Appeals on October 29, 2007. The record of decision (ROD) for the SEIS was signed by the BLM on December 30, 2008 and went into effect on January 14, 2009. The Suspension of Operations and Production for the suspended leases was terminated effective February 1, 2009. We have received letters from the BLM with amended lease terms of the affected leases. Leases that were suspended will be placed back into an active lease status with the primary term increasing for approximately three to five years based on the time period the leases were in suspension.

We were also granted suspension of certain state and federal leases in the Green River Basin totaling 4,481 gross (4,361 net) acres. The suspensions were requested primarily due to a lack of necessary infrastructure for well dewatering and gas transportation. In addition, the suspensions were granted pending approval of certain surface containment and discharge options by the BLM as well as completion of the BLM's environmental assessment of the Red Desert watershed area.

Natural Gas Reserves

The following table summarizes the reserve estimate and analysis of net proved reserves of natural gas as of December 31, 2006, 2007 and 2008, in accordance with SEC guidelines. The data for the periods listed was prepared by NSAI in Dallas, Texas. The present value of estimated future net revenues from these reserves was calculated on a non-escalated price basis discounted at 10% per year. As of December 31, 2008, there were no proved reserves related to our Green River Basin assets.

	As of December 31,		
	2006(2)	2007	2008(3)
Estimated net proved reserves:			
Proved developed producing (MMcf)	3,588	7,442	10,465
Proved developed non-producing (MMcf)	4,292	3,016	4,947
Total proved developed (MMcf)	7,880	10,458	15,412
Proved undeveloped (MMcf)	12,409	15,263	12,307
Total proved reserves (MMcf)	<u>20,289</u>	<u>25,721</u>	<u>27,719</u>
Future cash flows before income taxes (in millions)	\$ 34.8	\$ 65.0	\$ 47.3
Standardized measure (in millions)(1)	\$ 22.4	\$ 38.6	\$ 32.1
Price used for computing reserves (CIG index price per Mcf as of December 31)	\$ 4.460	\$ 6.040	\$ 4.605

- (1) The standardized measure of discounted future net cash flows represents the present value of future cash flows attributable to our proved reserves discounted at 10% after giving effect to income taxes, and as calculated in accordance with SFAS No. 69. Standardized measure does not represent an estimate of fair market value of our reserves.
- (2) Total proved reserves for 2006 declined primarily due to declines in the price of natural gas. Please see Item 1A, Risk Factors—Risks Related to Our Business—The volatility of natural gas and oil prices could have a material adverse effect on our business.
- (3) Future cash flows for 2008 declined primarily due to declines in the price of natural gas. Please see Item 1A, Risk Factors—Risks Related to our Business—The volatility of natural gas and oil prices could have a material adverse effect on our business.

Summary of Well Activity

Our drilling, recompletion, abandonment and acquisition activities for the periods indicated are shown below:

	Year Ended December 31,					
	2006		2007		2008	
	Gross	Net	Gross	Net	Gross	Net
Wells Drilled:						
Capable of Production	230	139	87	61	117	82
Dry	0	0	0	0	0	0
Wells Acquired	29	29	0	0	3	3
Wells Abandoned	1	1	1	1	16	9
Net Increase in Capable Wells	258	167	86	60	104	76

We had no exploratory wells as of December 31, 2008.

We are currently evaluating drilling plans for 2009 in light of the current economic and gas pricing environment.

Gas Gathering, Transportation and Compression

We have constructed and plan to continue to construct additional low-pressure gas gathering systems to transport natural gas from the wellhead to compression stations as part of the completion of a well. As of December 31, 2008, we owned and operated approximately 295 miles of low-pressure gas gathering pipelines primarily in the Recluse and Cabin Creek areas of Wyoming. We use third-party services to compress and transport our natural gas to market in return for compression and transportation fees.

We use Western Gas Resources, Inc. for compression and transportation services in our Squaw Creek area of the Recluse Prospect and Clear Creek Energy Services, LLC for compression services in the Ring of Fire area of our Recluse Prospect. We have constructed the low-pressure gathering infrastructure to the inlet of the compression facilities for both the Squaw Creek and Ring of Fire areas. Both Western Gas Resources and Clear Creek Energy Services charge a fee plus allocated fuel for compressing our gas. Western Gas Resources transports our gas to Glenrock on the Fort Union Gas Gathering Line where we take title to the gas and have the ability to sell the gas to a third party purchaser or to Western Gas Resources. Clear Creek Energy Services delivers our gas to us at the outlet of their compression facilities where we have the ability to sell the gas to a third party purchaser. Gas at the tailgate of Clear Creek Energy Services' compression facility can move north on Grasslands Pipeline or south on Thunder Creek Gas Gathering System.

We have a low-pressure gas gathering agreement and a high-pressure gathering and compression agreement with Bitter Creek Pipelines, LLC for the Kirby and Deer Creek areas. Under the low-pressure gas gathering agreement, Bitter Creek Pipelines constructed a central compression site to compress a maximum daily quantity of gas for delivery into Bitter Creek's Pipelines' high-pressure gathering line in exchange for a gathering payment comprised of a commodity rate based on average daily volumes and monthly demand charges based on the number of compression sites and compressors. Pursuant to the high-pressure gas gathering agreement, Bitter Creek Pipelines transports a maximum daily quantity of our gas on its high-pressure line in exchange for a demand fee, gathering rate and processing service fee, as applicable. The rates under these agreements will be adjusted annually for inflation. The Bitter Creek Pipelines high-pressure line delivers our gas to the Bitter Creek Landeck Compressor Station for redelivery north into Williston Basin Interstate Pipeline Company and/or south into Thunder Creek Gas Services, LLC and any other future delivery points on the Bitter Creek Pipelines system. The Bitter Creek Pipelines pipeline and compression facilities became

operational in late August 2006. The low-pressure gas gathering agreement has an initial term of ten years, and the high-pressure gas gathering agreement has an initial term of five years, in each case, from August 28, 2006, the effective date of the agreements. Each gas gathering agreement will be automatically renewable after the initial term on a month-to-month basis, unless terminated by either party upon 60 days notice. In addition, after five years, if Bitter Creek Pipelines determines that it is no longer economically feasible to provide services under the low-pressure gas gathering agreement, it may terminate the low-pressure gas gathering agreement in its sole discretion with 60 days written notice.

Pursuant to a gas gathering agreement, we utilize Cantera Gas Holdings, LLC to gather and compress our gas in the Cabin Creek area. We have connected this area to the Big Horn Gas Gathering Pipeline, which takes our gas to multiple outlets. Pursuant to a construction and field operation agreement between us and Bighorn Gas Gathering, L.L.C., a subsidiary of Cantera Natural Gas, Bighorn Gas Gathering is constructing and operating, and we agreed to pay the costs of the construction and operation of, the gas gathering extension that connects our properties in the Cabin Creek area to the Big Horn Gas Gathering Pipeline. The construction and operating agreement has an initial term of one year and continues on a month-to-month basis thereafter unless terminated by either party upon 90 days' written notice. For five years after October 18, 2006, the effective date of the agreement, Big Horn Gas Gathering has an option to purchase the gas gathering extension from us. Under certain circumstances, Big Horn Gas Gathering also has a right of first refusal with respect to the extension. In 2008, Cantera Gas Holdings, LLC and Big Horn Gas Gathering, LLC were acquired by Copano Natural Gas. Big Horn Gas Gathering has indicated its intention to purchase the gas gathering extension in 2009. In connection with the purchase of the gas gathering extension, we expect to amend the terms of the gas gathering agreement to provide further transportation alternatives for our gas.

In November 2006, we entered into a gas gathering agreement with Mountain Gas Resources, Inc. related to certain of our Green River Basin properties in Sweetwater County, Wyoming. The agreement provides that we may transport up to an average of 5 MMcf/day from those Green River Basin properties in exchange for a gathering and compression fee. The fees under this agreement will be adjusted annually for inflation. The term of this agreement is two years, continuing year to year until terminated by either party with thirty days' written notice. During the term of the agreement, if we determine that our gas deliverability from the dedicated area will exceed 3 MMcf/day, we may notify Mountain Gas Resources to initiate construction of an additional pipeline loop. Mountain Gas Resources may construct such loop at its own cost, a result of which the term of this agreement will extend for five years from the date of our notice, or we may pay the actual costs of construction directly and the term of this agreement will remain as initially established. Pursuant to this agreement, we have committed to deliver to Mountain Gas Resources all of the gas now or hereafter produced from all formations and all wells located within the dedicated area.

Natural gas in the Powder River Basin is transported by three intrastate gathering pipelines, Thunder Creek Gas Gathering, Fort Union Gas Gathering and the Kinder Morgan Lateral, and one interstate pipeline, the Grasslands Pipeline. According to the Wyoming Oil and Gas Conservation Commission, gas transported from the Powder River Basin as of December 31, 2008 was approximately 1.4 Bcf per day, with remaining available capacity of approximately 0.2 Bcf per day, or 14% of the total capacity. The gas is moved to marketing hubs in southern Wyoming or western North Dakota, where pipeline interconnections enable gas to move to distribution centers, primarily in the midwestern and southern United States. However, a surplus of natural gas arriving at these marketing hubs from the Powder River Basin and elsewhere relative to the available takeaway capacity from these hubs has caused Rocky Mountain gas to generally trade at a discount to the NYMEX natural gas index price. From January 1, 2007 through December 31, 2007, Rocky Mountain gas traded at a differential to the NYMEX natural gas index price that ranged from a premium of \$0.46 to a discount of \$7.42 with an average differential of a discount of \$3.06. From January 1, 2008 through December 31, 2008, Rocky

Mountain gas traded at a differential to the NYMEX natural gas index price that ranged from a premium of \$0.17 to a discount of \$6.26 with an average differential of a discount of \$2.45.

Transportation of natural gas and access to throughput capacity have a direct impact on natural gas prices in the Rocky Mountain region, where our operations are concentrated. As drilling activity increases throughout the Rocky Mountain region, additional production may come on line, which could cause bottlenecks or capacity constraints. Generally speaking, a surplus of natural gas production relative to available transportation capacity has a negative impact on prices. Conversely, as capacity increases, and bottlenecks are eliminated, prices generally increase. The Rockies Express Pipeline, which was completed to Audrain County, Missouri in early 2008, has increased takeaway capacity by approximately 2 Bcf per day from key marketing hubs. We expect that the completion of additional proposed pipelines will help reduce the differential between gas produced in the Rocky Mountain region and the NYMEX natural gas index price. Additional proposed pipelines are scheduled to be completed in late 2010 and 2011. General economic conditions and the future demand for natural gas may change the timing of proposed pipelines.

Marketing and Customers

We currently have a contract with Enserco Energy Inc. to purchase the gas at the tailgate of the Clear Creek compression facility in Recluse and at the Landeck compressor station for gas delivered from our Kirby and Deer Creek project areas. Pursuant to an agreement with United Energy Trading, United Energy Trading currently purchases our gas at Glenrock, Wyoming after the compression and transportation from our Squaw Creek and Cabin Creek areas. Both Enserco Energy and United Energy Trading have extensive experience in gas marketing services in the Rocky Mountain region and specifically in the Powder River Basin and surrounding gas producing basins. Our contractual arrangements with Enserco Energy and United Energy Trading are based on the CIG index price and are cancelable upon thirty and sixty days' written notice, respectively, if we determine there are more attractive purchasing arrangements in the marketplace. During the year ended December 31, 2007, Enserco Energy, United Energy Trading and Cantera Natural Gas purchased 58%, 36% and 5% of our gas sold, respectively. During the year ended December 31, 2008, Enserco Energy, and United Energy Trading purchased 46%, and 54% of our gas sold, respectively. In the event that Enserco Energy or United Energy Trading were to experience financial difficulties or were to no longer purchase our natural gas, we could, in the short-term, experience difficulty in our marketing of natural gas, which could adversely affect our results of operations.

Hedging Activities

We seek to reduce our exposure to unfavorable changes in natural gas prices, which are subject to significant and often volatile fluctuation, through the use of fixed-price contracts. Our fixed-price contracts are comprised of energy swaps and collars. These contracts allow us to predict with greater certainty the effective natural gas prices to be received for hedged production and provide a benefit to operating cash flows and earnings when market prices are less than the fixed prices provided by the contracts. However, we will not benefit from market prices that are higher than the fixed prices in the contracts for hedged production. Collar structures provide for participation in price increases and decreases to the extent of the ceiling prices and floors provided in those contracts. With regard to hedging arrangements, our credit facility provides that acceptable commodity hedging arrangements cannot be greater than 80 to 85%, depending on the measurement date, of our monthly production from our hydrocarbon properties that are used in the borrowing base determination, and that the fixed or floor price of our hedging arrangements must be equal to or greater than the gas price used by the lenders in determining the borrowing base.

The following table summarizes the estimated volumes, fixed prices, fixed-price sales and fair value attributable to the fixed-price contracts as of December 31, 2008. As of December 31, 2008, we had

hedged volumes through December 2009. Please see Note 6 and Note 20 of the notes to the audited financial statements appearing elsewhere in this report for further information regarding our derivatives.

	Year Ending December 31, 2009
	(Unaudited)
Natural Gas Collars:	
Contract volumes (MMBtu):	
Floor	730,000
Ceiling	730,000
Weighted-average fixed price per MMBtu(1)	
Floor	\$ 6.50
Ceiling	\$ 7.50
Fixed-price sales(2)	\$ 7.50
Fair value, net (thousands)(3)	\$ 1,707
Natural Gas Swaps:	
Contract volumes (MMBtu)	912,500
Weighted-average fixed price per MMBtu(1)	\$ 7.17
Fair value, net (thousands)(3)	\$ 2,638
Total Natural Gas Contracts:	
Contract volumes (MMBtu)	1,642,500
Fixed-price sales(2)	\$ 7.32
Fair value, net (thousands)(3)	\$ 4,345

- (1) Volumes hedged using the CIG index price published in the first issue of Inside FERC's Gas Market Report for each calendar month of the derivative transaction.
- (2) Assumes ceiling prices for natural gas collar volumes.
- (3) Fair value based on CIG index price in effect for each month as of December 31, 2008.

Competition

We compete with a number of other potential purchasers of oil and gas leases and producing properties, many of which have greater financial resources than we do. The bidding for oil and gas leases has become particularly intense in the Powder River Basin with bidders evaluating potential acquisitions with varying product pricing parameters and other criteria that result in widely divergent bid prices. The presence of bidders willing to pay prices higher than are supported by our evaluation criteria could further limit our ability to acquire oil and gas leases. In addition, low or uncertain prices for properties can cause potential sellers to withhold or withdraw properties from the market. In this environment, we cannot guarantee that there will be a sufficient number of suitable oil and gas leases available for acquisition or that we can obtain oil and gas leases or obtain financing for or participants to join in the development of prospects.

In addition to competition for leasehold acreage in the Powder River Basin, the oil and gas exploration and production industry is intensely competitive as a whole. We compete against well-established companies that have significantly greater financial, marketing, personnel and other resources than we do. This competition could have a material adverse effect on our ability to execute our plan and our profitability.

Seasonal Nature of Business

Generally, but not always, the demand for natural gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or hot summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. Seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other oil and natural gas operations in certain areas of the Rocky Mountain region. These seasonal anomalies can pose challenges for meeting our well drilling objectives and increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations.

Employee and Labor Relations

We have reduced our full-time employees to 38 as of April 9, 2009 as a result of cost cutting measures. We believe that our relationships with our current employees are good. None of our employees are covered by a collective bargaining agreement. From time to time, we use the services of independent consultants to perform various professional services, particularly in the areas of legal and regulatory services. Independent contractors often perform well drilling and production operations, including pumping, maintenance, dispatching, inspection and testing. Reductions in full-time employees were due to general economic conditions and low natural gas prices in the Rocky Mountain region. While we believe the employees in place are integral to our future business plans, our liquidity and ability to attract capital will determine future staffing levels.

We depend to a large extent on the services of certain key management personnel and the loss of any could have a material adverse effect on our operations. We do not maintain key-man life insurance with respect to any of our employees, including our executive officers.

Regulations

The natural gas industry is subject to regulation by federal, state and local authorities on matters such as employee health and safety, permitting, bonding and licensing requirements, air quality standards, water pollution, the treatment, storage and disposal of wastes, plant and wildlife protection, storage tanks, the reclamation of properties and plugging of oil wells after gas operations are completed, the discharge or release of materials into the environment, and the effects of gas well operations on groundwater quality and availability and on other resources.

In addition, the possibility exists that new legislation or regulations may be adopted or new interpretations of existing laws and regulations may be issued that would have a significant impact on our operations or our customers' ability to use gas and may require us or our customers to change our or their operations significantly or incur substantial costs.

Climate change regulation is one area of potential future environmental law development. Studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases," may be contributing to warming of the Earth's atmosphere. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of natural gas, are examples of greenhouse gases. The U.S. Congress is actively considering legislation to reduce emissions of greenhouse gases from sources within the U.S. between 2012 and 2050. In addition, at least 17 states have developed initiatives to regulate emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. The Environmental Protection Agency, or EPA, is separately considering whether it will regulate greenhouse gases as "air pollutants" under the existing federal Clean Air Act. Passage of climate control legislation or other regulatory initiatives by Congress or various states of the U.S. or the adoption of regulations by the EPA or analogous state agencies that regulate or restrict emissions of greenhouse gases, including methane or

carbon dioxide in areas in which we conduct business, could result in changes to the consumption and demand for natural gas and could have adverse effects on our business, financial position, results of operations and prospects. These changes could increase the costs of our operations, including costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our greenhouse gas emissions, pay any taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas emissions program.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and/or criminal penalties, the imposition of injunctive relief, or both. Moreover, changes in any of these laws and regulations could have a material adverse effect on our business. In view of the many uncertainties with respect to current and future laws and regulations, including their applicability to us, we cannot predict the overall effect of such laws and regulations on our future operations.

We believe that our operations comply in all material respects with applicable laws and regulations and that the existence and enforcement of such laws and regulations have no more restrictive effect on our method of operations than on other similar companies in the energy industry. We have internal procedures and policies to ensure that our operations are conducted in substantial regulatory compliance.

Environmental Regulation of Gas Operations

Numerous governmental permits, authorizations and approvals are required for gas operations. In order to obtain such permits, authorizations and approvals, we are, or may be, required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that any proposed exploration for or production of gas or related activities may have upon the environment. Compliance with the terms of such permits, authorizations and approvals and all other requirements imposed by such authorities may be costly and time consuming and may delay or limit commencement or continuation of exploration or production operations. Moreover, failure to comply may result in the imposition of significant fines, penalties and injunctions. Future legislation or regulations may increase and/or change the requirements for the protection of the environment, health and safety and, as a consequence, our activities may be more closely regulated. This type of legislation and regulation, as well as future interpretations of existing laws, may result in substantial increases in equipment and operating costs to us and delays, interruptions or a termination of operations, the extent of which cannot be predicted. Further, the imposition of new or revised environmental laws, regulations or requirements could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste.

While it is not possible to quantify the costs of compliance with all applicable federal, state and local environmental laws, those costs have been and are expected to continue to be significant. We did not make any capital expenditures for environmental control facilities for the years ended December 31, 2007 or 2008. Any environmental costs are in addition to well closing costs, property restoration costs and other, significant, non-capital environmental costs, including costs incurred to obtain and maintain permits, gather and submit required data to regulatory authorities, characterize and dispose of wastes and effluents, and maintain management operational practices with regard to potential environmental liabilities. Compliance with these federal and state environmental laws has substantially increased the cost of gas production, but is, in general, a cost common to all domestic gas producers.

The magnitude of the liability and the cost of complying with environmental laws cannot be predicted with certainty due to the lack of specific environmental, geologic, and hydrogeologic information available with respect to many sites, the potential for new or changed laws and regulations, the development of new drilling, remediation, and detection technologies and environmental controls, and the uncertainty regarding the timing of work with respect to particular sites. As a result, we may

incur material liabilities or costs related to environmental matters in the future and such environmental liabilities or costs could adversely affect our results and financial condition. In addition, there can be no assurance that changes in laws or regulations would not affect the manner in which we are required to conduct our operations. Further, given the retroactive nature of certain environmental laws, we have incurred, and may in the future incur, liabilities associated with: the investigation and remediation of the release of hazardous substances, oil, natural gas, other petroleum products or other substances; environmental conditions; and damage to natural resources arising from properties and facilities currently or previously owned or operated as well as sites owned by third parties to which we sent waste materials for disposal.

We may be subject to various generally applicable federal environmental and related laws, including the following:

- the Clean Air Act;
- the Federal Water Pollution Control Act/Clean Water Act;
- the National Environmental Policy Act;
- the Federal Land Policy and Management Act;
- the Safe Drinking Water Act;
- the Toxic Substances Control Act;
- the Comprehensive Environmental Response, Compensation and Liability Act (Superfund);
- the Solid Waste Disposal Act/Resource Conservation and Recovery Act;
- the Emergency Planning and Community Right to Know Act; and
- the Endangered Species Act;

as well as state laws of similar scope and substance in each state in which we operate.

Regulatory requirements not directly applicable to us, but governing the ability of federal, state, or local governments to issue approvals, permits, or authorizations, or to take other actions, may also affect our operations. Such requirements include, without limitation, the National Environmental Policy Act and similar state statutory or regulatory requirements.

These environmental laws require monitoring, reporting, permitting and/or approval of many aspects of gas operations. Both federal and state inspectors regularly inspect facilities during construction and during operations after construction. We have ongoing environmental management, compliance and permitting programs designed to assist in compliance with such environmental laws. We believe that we have obtained or are in the process of obtaining all required permits under federal and state environmental laws for our current gas operations. Further, we believe that we are in substantial compliance with such permits. However, violations of permits, failure to obtain permits or other violations of federal or state environmental laws could cause us to incur significant liabilities to correct such violations, to provide additional environmental controls, to obtain required permits or to pay fines which may be imposed by governmental agencies. New permit requirements and other requirements imposed under federal and state environmental laws may cause us to incur significant additional costs that could adversely affect our operating results.

Some laws, rules and regulations relating to the protection of the environment may, in certain circumstances, impose “strict liability” for environmental contamination. Such laws render a person or company liable for environmental and natural resource damages, cleanup costs and, in the case of oil spills in certain states, consequential damages without regard to negligence or fault. Other laws, rules and regulations may require the rate of natural gas and oil production to be below the economically

optimal rate or may even prohibit exploration or production activities in environmentally sensitive areas.

Common law theories of recovery may apply to operations where the presence, release, storage, transportation or use of natural gas or production waste is alleged to cause personal injury, illness or property damage as a result. The theories of negligence, trespass and strict liability have been used by land owners, individuals or trespassers to invoke claims for recovery of personal injuries, illness, property damage, loss of profits and related claims. Generally, such common law claims by third parties are not preempted by federal or state environmental laws, rules or regulations and may be used by plaintiffs in state law claims or as supplemental jurisdiction claims in conjunction with federal or state statutory environmental litigation.

In addition, state laws often require some form of remedial action such as closure of inactive pits and plugging of abandoned wells to prevent pollution from former or suspended operations. Legislation has been proposed and continues to be evaluated in Congress from time to time that would reclassify certain natural gas and oil exploration and production wastes as “hazardous wastes.” This reclassification would make such wastes subject to much more stringent and expensive storage, treatment, disposal and clean up requirements. If such legislation were to be enacted, it could have a significant adverse impact on our operating costs, as well as the natural gas and oil industry in general. Initiatives to regulate further the disposal of natural gas and oil wastes are also proposed in certain states from time to time and may include initiatives at county, municipal and local government levels. These various initiatives could have a similar adverse impact on us.

From time to time, we have been the subject of investigations, administrative proceedings and litigation by government agencies and third parties relating to environmental matters. We may become involved in future proceedings, litigation or investigations and incur liabilities that could be materially adverse to us.

Federal Regulation of the Sale and Transportation of Gas

Various aspects of our operations are regulated by agencies of the federal government. The Federal Energy Regulatory Commission, or FERC, regulates the transportation and sale of natural gas in interstate commerce pursuant to the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. In the past, the federal government has regulated the prices at which gas could be sold. While “first sales” by producers of natural gas, and all sales of condensate and natural gas liquids, can be made currently at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead sales in the natural gas industry began with the enactment of the Natural Gas Policy Act in 1978. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all Natural Gas Act and Natural Gas Policy Act price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993.

We own certain natural gas in-field low-pressure pipelines that we believe meet the traditional tests which FERC has used to establish a pipeline’s status as a gatherer under section 1(b) of the Natural Gas Act, 16 U.S.C. § 717(b) and are therefore not subject to FERC jurisdiction.

Additional proposals and proceedings that might affect the gas industry are pending before Congress, FERC, the Minerals Management Service, state commissions and the courts. We cannot predict when or whether any such proposals may become effective. In the past, the natural gas industry has been heavily regulated. There is no assurance that the regulatory approach currently pursued by various agencies will continue indefinitely. Notwithstanding the foregoing, we do not anticipate that compliance with existing federal, state and local laws, rules and regulations will have a material or significantly adverse effect upon our capital expenditures, earnings or competitive position. No material portion of our business is subject to renegotiation of profits or termination of contracts or subcontracts at the election of the federal government.

Beginning in 1992, FERC issued a series of orders (“Order No. 636”) which required interstate natural gas pipelines to provide transportation service separate or unbundled from the pipeline’s sales of gas. In addition, Order No. 636 required interstate natural gas pipelines to provide open access transportation on a non-discriminatory basis that treats similarly situated shippers equally. The courts affirmed the significant features of Order No. 636 and numerous related orders pertaining to the individual pipelines, and FERC has since reviewed and modified its open access regulations. In particular, FERC has reviewed its transportation regulations, including how they operate in conjunction with state proposals for retail gas marketing restructuring, whether to eliminate cost of service rates for short-term transportation, whether to allocate all short-term capacity on the basis of competitive auctions, and whether changes to its long-term transportation policies may also be appropriate to avoid a market bias toward short-term contracts. In February 2000, FERC issued Order No. 637 amending certain regulations governing interstate natural gas pipeline companies in response to the development of more competitive markets for natural gas and natural gas transportation. The goal of Order No. 637 is to “fine tune” the open access regulations implemented by Order No. 636 to accommodate subsequent changes in the market. Key provisions of Order No. 637 include:

- (1) waiving the price ceiling for short-term capacity release transactions until September 30, 2002 (which was reversed pursuant to an order on remand issued by FERC on October 31, 2002);
- (2) permitting value oriented peak/off peak rates to better allocate revenue responsibility between short-term and long-term markets;
- (3) permitting term differentiated rates, in order to better allocate risks between shippers and the pipeline;
- (4) revising the regulations related to scheduling procedures, capacity, segmentation, imbalance management, and penalties;
- (5) retaining the right of first refusal and the five year matching cap for long-term shippers at maximum rates, but significantly narrowing the right of first refusal for customers that FERC does not deem to be captive; and
- (6) adopting new web site reporting requirements that include daily transactional data on all firm and interruptible contracts and daily reporting of scheduled quantities at points or segments.

The new reporting requirements became effective on September 1, 2000. FERC has also issued numerous orders confirming the sale and abandonment of natural gas gathering facilities previously owned by interstate pipelines and acknowledging that if FERC does not have jurisdiction over services provided by these facilities, then such facilities and services may be subject to regulation by state authorities in accordance with state law. A number of states have either enacted new laws or are considering the adequacy of existing laws affecting gathering rates and/or services. Other state regulation of gathering facilities generally includes various safety, environmental, and in some circumstances, nondiscriminatory take requirements, but does not generally entail rate regulation. Thus, natural gas gathering may receive greater regulatory scrutiny of state agencies in the future. Our low-pressure gathering operations could be adversely affected should they be subject in the future to increased state regulation of rates or services. In addition, FERC’s approval of transfers of previously regulated gathering systems to independent or pipeline affiliated gathering companies that are not subject to FERC regulation may affect competition for gathering or natural gas marketing services in areas served by those systems and thus may affect both the costs and the nature of gathering services that will be available to interested producers or shippers in the future.

State Regulation of Gas Operations

Our operations are also subject to regulation at the state and, in some cases, the county, municipal and local governmental levels. Such regulations include requiring permits for the construction, drilling

and operation of wells, maintaining bonding requirements in order to drill or operate wells, regulating the surface use and requiring the restoration of properties upon which wells are drilled, requiring the proper plugging and abandonment of wells, and regulating the disposal of fluids used and produced in connection with operations. Our operations are also subject to various state conservation laws and regulations. These include regulations that may affect the size of drilling and spacing units or proration units, the density of wells which may be drilled, and the mandatory unitization or pooling of gas properties. In addition, state conservation regulations may establish the allowable rates of production from gas wells, may prohibit or regulate the venting or flaring of gas, and may impose certain requirements regarding the ratability of gas production. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory and nonpreferential purchase and/or transportation requirements, but does not generally entail rate regulation. These regulatory burdens may affect profitability, and we are unable to predict the future cost or impact of complying with such regulations.

Permitting Issues for Federal Lands

Approximately 67% and 61% of our gross acreage in Montana and Wyoming, respectively, is on U.S. federal land. Federal leases in Montana and Wyoming must be developed pursuant to the U.S. BLM's Resource Management Plans. Federal leases are also subject to the National Environmental Policy Act and Federal Land Policy Management Act. The National Environmental Policy Act process imposes obligations on the federal government that may result in legal challenges and potentially lengthy delays in obtaining project permits or approvals. The Montana and Wyoming BLMs have been subject to several lawsuits from various environmental and tribal groups challenging Resource Management Plan amendments and supporting Environmental Impact Statements addressing CBM development in Montana and Wyoming. In 2003, the Montana BLM and Wyoming BLM each amended their Resource Management Plans based in part on Environmental Impact Statements prepared pursuant to the National Environmental Policy Act. Shortly after the issuance of the Environmental Impact Statements and amended Resource Management Plans, various plaintiffs brought legal actions challenging the Montana and Wyoming Environmental Impact Statements and Resource Management Plans. There have been at least five federal district court challenges to the Montana Environmental Impact Statements. There are also at least three federal district court challenges to the Wyoming Environmental Impact Statements currently pending before the United States District Court for the District of Wyoming.

In April and June 2005, the Montana BLM in Miles City, Montana issued suspensions of operations for the majority of our federal leases in Montana. The suspensions were issued based upon the court order issued on April 5, 2005 by the U.S. District Court of Montana which required the BLM to complete a SEIS to address phased development of coal bed natural gas. The U.S. Ninth Circuit Court of Appeals also issued an order on May 31, 2005 which enjoined the BLM from approving coal bed natural gas production projects in the Powder River Basin of Montana. Both of these actions placed limitations on lease development until completion of the SEIS.

The injunction on the development of federal leases in Montana was effectively lifted on February 1, 2009. As a result, leases that were suspended during the injunction will be placed back into an active lease status with the primary term increasing for approximately three to five years due to the time period the leases were in suspension.

In December 2007, the U.S. BLM imposed a permitting application fee of \$4,000 per well drilled on federal lands. This fee increased our regulatory costs in 2008 by an additional \$1.0 million and could affect the timing of our development of federal leases.

In addition to federal regulation, our federal leases are subject to certain state regulations which require governmental agencies to evaluate the potential environmental impact of a proposed project on government owned lands.

We have dedicated significant resources to managing regulatory and permitting matters to achieve efficient processing of federal permits and resource management plans. We believe we are making significant progress in resolving the outstanding regulatory and environmental issues in Montana and Wyoming.

Employee Health and Safety

We are subject to the requirements of the Occupational Safety and Health Act, or OSHA, and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements and general industry standards regarding recordkeeping requirements and the monitoring of occupational exposure to regulated substances.

ITEM 1A RISK FACTORS

The following are some of the important factors that could affect our financial performance or could cause actual results to differ materially from estimates contained in our forward-looking statements. We may encounter risks in addition to those described below. Additional risks and uncertainties not currently known to us, or that we currently deem to be immaterial, may also impair or adversely affect our business, financial condition or results of operation.

Risks Related to Our Business

Due to the recent financial and credit crisis, we may not be able to obtain funding, or obtain funding on acceptable terms, to meet our future capital needs, which could negatively affect our business, results of operations and financial condition.

The continued credit crisis and the related turmoil in the global financial system have had an adverse impact on our business and financial condition, and we may face major challenges if conditions in the financial markets do not improve. Currently, we are not able to borrow additional amounts under our credit facility. As a result, we curtailed substantially all new drilling in the fourth quarter of 2008, and if our operating cash flow is not sufficient to carry out our drilling plans for 2009, we will be required to reduce the number of wells we drill or seek alternative sources of financing. However, due to the financial crisis, financing through the capital markets or otherwise may not be available to us on acceptable terms or at all. If additional funding is not available, or is available only on unfavorable terms, we may be unable to implement our drilling plans, make capital expenditures, withstand a further downturn in our business or the economy in general, or take advantage of business opportunities that may arise. Any further curtailment of our operations would have an additional adverse effect on our revenues and results of operations. In addition, current economic conditions have led to reduced demand for, and lower prices of, oil and natural gas, and a sustained decline in the price of natural gas would adversely affect our business, results of operations and financial condition. Please read “The volatility of natural gas and oil prices could have a material adverse effect on our business” below. Further, the economic situation could have an impact on our lenders or customers, causing them to fail to meet their obligations to us, and on the liquidity of our operating partners, resulting in delays in operations or their failure to make required payments. Also, market conditions

could have an impact on our natural gas and oil derivatives transactions if our counterparties are unable to perform their obligations or seek bankruptcy protection.

Our credit facility has substantial restrictions and financial covenants that may affect our ability to successfully operate our business. In addition, we may have difficulty returning to compliance with certain financial covenants.

Our credit facility imposes certain operational and financial restrictions on us. These restrictions, among other things, limit our ability to:

- incur additional indebtedness;
- create liens;
- sell our assets or consolidate or merge with or into other companies;
- make investments and other restricted payments, including dividends; and
- engage in transactions with affiliates.

These limitations are subject to a number of important qualifications and exceptions. In addition, our credit facility requires us to maintain certain financial ratios and to satisfy certain financial conditions which may require us to reduce our debt or to take some other action in order to comply with them. These restrictions in our credit facility could also limit our ability to obtain future financings, make needed capital expenditures, withstand a downturn in our business or the economy in general, or otherwise conduct necessary corporate activities. We also may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants under our credit facility.

We are not in compliance with the current ratio financial covenant and certain other covenants related to accounts payable, permitted liens and permitted debt under our credit facility, and would be in default absent a waiver or amendment. On April 14, 2009, the lenders waived compliance with the current ratio as of December 31, 2008 and March 31, 2009, and with such other restrictive covenants, subject to certain financial caps, until the next borrowing base redetermination expected in the fall of 2009. We have also not been in compliance with certain financial covenants for the last four quarters, including the first quarter of 2009, but obtained waivers and/or amendments in each instance. As a result of such non-compliance, we are unable to borrow additional funds under our credit agreement. We believe that we may not be in compliance with certain restrictive covenants throughout 2009, but will seek additional waivers. There can be no assurance that we will be able to obtain such waivers or that such waivers will be obtained on acceptable terms. If we are unable to obtain future waivers and/or to comply with the restrictive covenants, the lenders could accelerate our indebtedness or foreclose on properties held by liens. In addition, due to borrowing base limitations, we are currently unable to borrow additional funds under the credit facility. In connection with the waiver of the restrictive covenants, the lenders reduced our borrowing base to \$9.0 million, with further monthly reductions until the borrowing base reaches \$6.5 million on October 1, 2009. If natural gas prices do not improve, we expect that our borrowing base could be further reduced in the future.

Please see Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Credit Facility,” for a discussion of our credit facility.

Our development activities could require significant outside capital, which may not be available or could change our risk profile.

We expect to make substantial capital expenditures in the development of natural gas reserves in the future as part of our business strategy. In general, we intend to finance our capital expenditures in the future through cash flow from operations and the incurrence of indebtedness. However, due to

limitations in our credit facility, we are currently unable to borrow additional amounts. In addition, our business experienced reduced cash flows during the fourth quarter of 2008 due to low natural gas prices. Future cash flows and the availability of financing will be subject to a number of variables such as:

- the level of production from existing wells;
- prices of natural gas and oil;
- our results in locating and producing new reserves;
- the success and timing of development of proved undeveloped reserves; and
- general economic, financial, competitive, legislative, regulatory and other factors beyond our control.

If we are unable to fund our planned activities with the combination of cash flow from operations and availability under our credit facility, we may have to obtain additional financing through the issuance of debt and/or equity. Recent conditions in the financial markets have had an adverse impact on our ability to access equity and capital markets. As a result, the availability of credit has become more expensive and difficult to obtain, and the cost of equity capital has also become more expensive. Some lenders are imposing more stringent restrictions on the terms of credit and there may be a general reduction in the amount of credit available in the markets in which we conduct business. The negative impact on the tightening of the credit markets will have a material adverse effect on us. In addition, the distribution levels of new equity issued may be higher than our historical levels, making additional equity issuances more expensive. Further, issuing equity securities to satisfy our financing requirements could cause substantial dilution to our stockholders. The level of our debt financing could also materially affect our operations and significantly affect our financial risk profile.

If our revenues decrease due to lower natural gas and oil prices, decreased production or other reasons, and if we could not obtain capital through our credit facility or otherwise, our ability to execute our development and acquisition plans, replace our reserves or maintain production levels could be greatly limited.

The volatility of natural gas and oil prices could have a material adverse effect on our business.

Our revenues, profitability and future growth and the carrying value of our natural gas and oil properties depend to a large degree on prevailing natural gas and oil prices. Our ability to maintain or increase our borrowing capacity and to obtain additional capital on attractive terms also substantially depends upon natural gas and oil prices. Prices for natural gas and oil are subject to large fluctuations in response to relatively minor changes in the supply and demand for natural gas and oil, uncertainties within the market and a variety of other factors in large part beyond our control, such as:

- the domestic and foreign supply of natural gas and oil;
- the activities of the Organization of Petroleum Exporting Countries and state-owned oil companies relating to oil price and production controls;
- overall domestic and global economic and political conditions;
- the consumption pattern of industrial consumers, electricity generators and residential users;
- the availability of transportation systems with adequate capacity;
- price and availability of alternative fuels;
- weather conditions and fluctuating seasonal demand;
- natural disasters;

- acts of terrorism;
- political stability in the Middle East and elsewhere;
- domestic and foreign governmental regulations, including conservation efforts and taxation;
- the price and quantity of foreign imports; and
- the price and availability of alternative fuels.

In the past, natural gas prices have been extremely volatile, and we expect this volatility to continue. During the year ended December 31, 2007, the NYMEX natural gas index price ranged from a high of \$8.64 per MMBtu to a low of \$5.38 per MMBtu, while the CIG natural gas index price ranged from a high of \$7.11 per MMBtu to a low of \$0.06 per MMBtu. For example, during the year ended December 31, 2008, the NYMEX natural gas index price ranged from a high of \$13.58 per MMBtu to a low of \$5.29 per MMBtu, while the CIG natural gas index price ranged from a high of \$10.26 per MMBtu to a low of \$1.00 per MMBtu.

In addition to downward pressure on prices caused by reduced domestic demand, some analysts expect near-term domestic gas prices to fall further due to additional gas supplies from lower-cost resource plays, including shale, that use new exploration and production technologies and from foreign gas imports through existing and new natural gas liquefaction capacity.

A sharp decline in natural gas prices would result in a commensurate reduction in our revenues, income and cash flows from the production of natural gas and could have a material adverse effect on our borrowing base and proved reserves. In the event prices fall substantially, we may not be able to realize a profit from our production and would operate at a loss, and even relatively modest drops in prices can significantly affect our financial results and impede our growth. Due to a decline in the price of natural gas during the third quarter and the beginning of the fourth quarter, we curtailed substantially all new drilling for the fourth quarter of 2008 and have shut-in a number of wells that are not economic at current natural gas price levels.

Lower natural gas prices may not only decrease our revenues on a per unit basis, but also may reduce the amount of natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. For example, if natural gas prices decline by \$0.10 per Mcf, then the pre-tax PV-10 of our proved reserves as of December 31, 2008 would decrease from \$32.8 million to \$31.7 million.

Low natural gas prices may result in impairments of our oil and gas properties.

Accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our properties for impairments. As such, we may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period such impairment charges are taken. We reported impairments of our oil and gas properties of approximately \$21.5 million and \$18.2 million for the years ended December 31, 2008 and 2007, respectively, due to low CIG index prices. Based on the CIG index price of \$2.20 per Mcf on April 9, 2009, we would have been required to take a total impairment of approximately \$46.7 million at December 31, 2008. A further decline in gas prices or an increase in operating costs subsequent to the measurement date or reductions in the economically recoverable quantities could result in the recognition of additional impairments of our gas properties in future periods.

Approximately 62% of our total proved reserves as of December 31, 2008 consisted of undeveloped and developed non-producing reserves, and those reserves may not ultimately be developed or produced.

As of December 31, 2008, approximately 18% of our total proved reserves were undeveloped and approximately 44% were developed non-producing. We plan to develop and produce all of our proved

reserves in the future, but ultimately some of these reserves may not be developed or produced. Furthermore, not all of our undeveloped or developed non-producing reserves may be ultimately produced in the time periods we have planned, at the costs we have budgeted, or at all. Due to expectations of low natural gas prices in 2009, we have deferred drilling of our undeveloped reserves to future years which has affected the present value of future net cash flows for these reserves.

Our estimated reserves are based on many assumptions, some of which may prove to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

This annual report contains estimates of natural gas reserves, and the future net cash flows attributable to those reserves, prepared by Netherland, Sewell & Associates, Inc., our independent petroleum and geological engineers. There are numerous uncertainties inherent in estimating quantities of proved reserves and cash flows from such reserves, including factors beyond our and Netherland, Sewell & Associates, Inc.'s control. Reserve engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The accuracy of an estimate of quantities of reserves, or of cash flows attributable to those reserves, is a function of: (1) the available data; (2) the accuracy of assumptions regarding future natural gas and oil prices and future development and exploitation costs and activities; and (3) engineering and geological interpretation and judgment. Reserves and future cash flows may be subject to material downward or upward revisions based upon production history, development and exploitation activities and natural gas and oil prices. Actual future production, revenue, taxes, development expenditures, operating expenses, quantities of recoverable reserves and value of cash flows from those reserves may vary significantly from the assumptions and estimates in this report. Any significant variance between these assumptions and actual figures could greatly affect our estimates of reserves, the economically recoverable quantities of natural gas attributable to any particular group of properties, the classification of reserves based on risk of recovery, and estimates of future net cash flows. In addition, reserve engineers may make different estimates of reserves and cash flows based on the same available data. The estimated quantities of proved reserves and the discounted present value of future net cash flows attributable to those reserves included in this annual report were prepared by Netherland, Sewell & Associates, Inc. in accordance with the rules of the Securities and Exchange Commission, or SEC, and are not intended to represent the fair market value of such reserves.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated natural gas reserves. We base the estimated discounted future net cash flows from our proved reserves on prices and costs. However, actual future net cash flows from our natural gas and oil properties also will be affected by factors such as:

- geological conditions;
- changes in governmental regulations and taxation;
- assumptions governing future prices;
- the amount and timing of actual production;
- future operating costs; and
- the capital costs of drilling new wells.

The timing of both our production and our incurrence of expenses in connection with the development and production of natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor

based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

We may not be able to find, acquire or develop additional natural gas reserves that are economically recoverable.

The rate of production from natural gas and oil properties declines as reserves are depleted. As a result, we must locate, acquire and develop new natural gas and oil reserves to replace those being depleted by production. We must do this even during periods of low natural gas and oil prices when it is difficult to raise the capital necessary to finance activities. Our future natural gas reserves and production and, therefore, our cash flow and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to find or acquire and develop additional reserves at an acceptable cost or have necessary financing for these activities in the future.

The development of natural gas properties involves substantial risks that may result in a total loss of investment.

The business of exploring for, developing and operating natural gas and oil properties involves a high degree of business and financial risks, and thus a substantial risk of investment loss that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The cost of drilling, completing and operating wells is often uncertain, and a number of factors can delay or prevent drilling operations or production, including:

- unexpected or adverse drilling conditions;
- elevated pressure or irregularities in geologic formations;
- equipment failures, repairs or accidents;
- title problems;
- fires, explosions, blowouts, cratering, pollution and other environmental risks or other accidents;
- compliance with governmental regulations;
- adverse weather conditions;
- reductions in natural gas and oil prices;
- pipeline ruptures;
- unavailability or high cost of drilling rigs, other field services, equipment and labor; and
- limitations in the market for oil and gas.

A productive well may become uneconomic in the event that unusual quantities of water or other deleterious substances are encountered, which impair or prevent the production of natural gas and/or oil from the well. In addition, production from any well may be unmarketable if it is contaminated with unusual quantities of water or other deleterious substances. We may drill wells that are unproductive or, although productive, do not produce natural gas and/or oil in economic quantities. Unsuccessful drilling activities could result in higher costs without any corresponding revenues. Furthermore, a successful completion of a well does not ensure a profitable return on the investment.

We may not adhere to our proposed drilling schedule.

Our final determination of whether to drill any scheduled or budgeted wells will be dependent on a number of factors, including:

- the results of our exploration efforts and the acquisition, review and analysis of data;
- the availability of sufficient capital resources to us and the other participants for the drilling of the prospects;
- the approval of the prospects by the other participants after additional data has been compiled;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for natural gas and oil and the availability and prices of drilling rigs and crews; and
- the availability of leases and permits on reasonable terms for the prospects.

We must obtain governmental permits and approvals for drilling operations, which can result in delays in our operations, be a costly and time consuming process, and result in restrictions on our operations.

Regulatory authorities exercise considerable discretion in the timing and scope of permit issuances in the Rocky Mountain region. Compliance with the requirements imposed by these authorities can be costly and time consuming and may result in delays in the commencement or continuation of our exploration or production operations and/or fines. For example, in the ordinary course of our business, we have received notices of violation or orders to cease production with respect to certain of our wells that have resulted in production delays and/or fines. Similar regulatory or legal actions in the future may materially interfere with our operations or otherwise have a material adverse effect on us. In addition, we are often required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that a proposed project may have on the environment, threatened and endangered species, and cultural and archaeological artifacts. Further, the public may comment on and otherwise engage in the permitting process, including through intervention in the courts. Accordingly, the permits we need may not be issued, or if issued, may not be issued in a timely fashion, or may involve requirements that restrict our ability to conduct our operations or to do so profitably. For example, in December 2007, the U.S. BLM imposed a permitting application fee of \$4,000 per well drilled on federal lands. This fee increased our regulatory costs in 2008 by an additional \$1.0 million and affected the timing of our development of federal leases.

Our natural gas sales are dependent on two customers and the loss of these customers or their inability to pay for our gas would adversely affect our ability to market our gas.

We market substantially all our natural gas to two purchasers. During the year ended December 31, 2008, Enserco Energy and United Energy Trading purchased 46% and 54% of our gas sold, respectively. In the event that Enserco Energy or United Energy Trading experienced financial difficulties or no longer purchased our natural gas, we could, in the short-term, experience difficulty in our marketing of natural gas, which could adversely affect our results of operations.

We may be adversely affected by natural gas prices in the Rocky Mountain region.

Substantially all of our properties are geographically concentrated at the northern end of the Rocky Mountain region. The price received by us for the natural gas production from these properties is determined mainly by factors affecting the regional supply of and demand for natural gas, as well as the general availability of pipeline capacity to deliver natural gas to the market. Based on recent experience, regional differences could cause a negative basis differential between the published indices generally used to establish the price received for regional natural gas production and the actual price we receive for natural gas production. For example, from January 1, 2008 through December 31, 2008,

Rocky Mountain gas traded at a differential to the NYMEX natural gas index price that ranged from a premium of \$0.17 to a discount of \$6.26, and the differential averaged a discount of \$2.45.

The majority of our properties are located in a five-county region in the northern end of the Powder River Basin in northeastern Wyoming and southern Montana, making us vulnerable to risks associated with having our production concentrated in one area.

The majority of our properties are geographically concentrated in a five-county region in the northern end of the Powder River Basin in northeastern Wyoming and southern Montana. As a result of this concentration, we may be disproportionately exposed to the impact of delays or interruptions of production from these properties caused by significant governmental regulation, transportation capacity constraints, curtailment of production, natural disasters, adverse weather conditions or other events which impact this area.

We may suffer losses or incur liability for events for which we or the operator of a property have chosen not to obtain insurance.

Our operations are subject to hazards and risks inherent in producing and transporting natural gas and oil, such as fires, natural disasters, explosions, pipeline ruptures, spills and acts of terrorism, all of which can result in the loss of hydrocarbons, environmental pollution, personal injury claims and other damage to our and others' properties. As protection against operating hazards, we maintain insurance coverage against some, but not all, potential losses. In addition, pollution and environmental risks generally are not fully insurable. As a result of market conditions, existing insurance policies may not be renewed and other desirable insurance may not be available on commercially reasonable terms, if at all. The occurrence of an event that is not covered, or not fully covered, by insurance could have a material adverse effect on our business, financial condition and results of operations.

Our use of hedging arrangements could result in financial losses or reduce our income.

We currently engage in hedging arrangements to reduce our exposure to fluctuations in the prices of natural gas for a significant portion of our current natural gas production. These hedging arrangements expose us to risk of financial loss in some circumstances, including when production is less than expected, the counterparty to the hedging contract defaults on its contract obligations, or there is a change in the expected differential between the underlying price in the hedging agreement and the actual price received. In addition, these hedging arrangements may limit the benefits we would otherwise receive from increases in prices for natural gas. Please see Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Item 7A, Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk and Items 1 and 2, Business and Properties—Operations—Hedging Activities.

Our business depends on gathering and transportation facilities owned by others. Any limitation in the availability of those facilities would interfere with our ability to market the natural gas we produce.

The marketability of our natural gas production depends in part on the availability, proximity and capacity of gathering and pipeline systems owned by third parties. The amount of natural gas that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering or transportation system, or lack of contracted capacity on such systems. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we are provided only with limited, if any, notice as to when these circumstances will arise and their duration. For example, although volumes increased in 2008 overall, our volumes were reduced by approximately 1.3 MMcf per day from September 1, 2008 through December 31, 2008 due to low natural gas pricing, weather interruptions and pipeline flow interruptions due to hydrostatic testing.

In addition, some of our wells are drilled in locations that are not serviced by gathering and transportation pipelines, or the gathering and transportation pipelines in the area may not have sufficient capacity to transport the additional production. As a result, we may not be able to sell the natural gas production from these wells until the necessary gathering and transportation systems are constructed. Any significant curtailment in gathering system or pipeline capacity, or significant delay in the construction of necessary gathering and transportation facilities, would have an adverse effect on our business.

Shortages of drilling rigs and equipment and experienced personnel could delay our operations.

Higher natural gas prices generally increase the demand for drilling rigs and equipment, field services and personnel with drilling or other oil and gas operational experience, and can lead to shortages of, and increasing costs or wages for, such equipment, services and personnel. Shortages of, or increasing costs for, experienced operational personnel and oil field equipment and services could restrict our ability to drill the wells and conduct the operations which we currently have planned. Any delay in the drilling of new wells or significant increase in wages or drilling or other operational costs could reduce our revenues.

We may incur losses as a result of title deficiencies in the properties in which we invest.

It is our practice in acquiring natural gas and oil leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest. Rather, we rely upon the judgment of natural gas and oil lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest.

Prior to the drilling of a natural gas or oil well, however, it is the normal practice in our industry for the person or company acting as the operator of the well to obtain a preliminary title review to ensure there are no obvious deficiencies in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct deficiencies in the marketability of the title, and such curative work entails expense. A title review conducted in connection with our credit facility revealed title defects on numerous properties. We have cured these defects and do not believe they will have a material adverse effect on our business or operations. Our failure to cure any future title defects may adversely impact our ability in the future to increase production and reserves. In addition, if a title review reveals that a lease or interest has been purchased in error from a person who was not the owner, our interest would be worthless.

We may incur losses in our acreage position due to the expiration of leases.

Our leasehold position is subject to leases with terms which expire from 2009 to 2018. Our leases may not be held by production and may consequently expire if we are unable to develop them in a

timely manner. In addition, leases held by production which are subsequently shut-in due to low natural gas prices may also expire if we are unable to make shut-in payments.

We are subject to environmental regulation that can materially adversely affect the timing and cost of our operations.

Our exploration and production activities are subject to certain federal, state and local laws and regulations relating to environmental quality and pollution control. These laws and regulations increase the costs of these activities and may prevent or delay the commencement or continuance of a given operation. Specifically, we are subject to legislation regarding the acquisition of permits before drilling, restrictions on drilling activities in restricted areas, emissions into the environment, water discharges, and storage and disposition of hazardous wastes. In addition, legislation has been enacted which requires well and facility sites to be abandoned and reclaimed to the satisfaction of state authorities. Such laws and regulations have been frequently changed in the past, and we are unable to predict the ultimate cost of compliance as a result of any future changes. The adoption or enforcement of stricter regulations could have a significant impact on our operating costs, as well as on the natural gas and oil industry in general. Compliance with environmental laws and regulations can be very complex, and therefore, no assurances can be given that such environmental laws and regulations will not have a material adverse effect on our business, financial condition and results of operations.

Our operations could result in liability for personal injuries, property damage, discharge of hazardous materials, remediation and clean up costs and other environmental damages. We could also be liable for environmental damages caused by previous property owners. As a result, substantial liabilities to third parties or governmental entities may be incurred which could have a material adverse effect on our financial condition and results of operations. We maintain insurance coverage for our operations, but we do not believe that insurance coverage for environmental damages that occur over time, or complete coverage for sudden and accidental environmental damages, is available at a reasonable cost. Accordingly, we may be subject to liability or may lose the right to continue exploration or production activities upon substantial portions of our properties if certain environmental damages occur.

We are subject to complex governmental regulations which may materially adversely affect the cost of our business and result in delays in our operations.

Numerous departments and agencies, both federal and state, are authorized by statute to issue and have issued rules and regulations binding on the natural gas and oil industry and its individual members, some of which carry substantial penalties for failure to comply. We may be required to make large expenditures to comply with these regulatory requirements. Any increases in the regulatory burden on the natural gas and oil industry created by new legislation would increase our cost of doing business and could result in delays in our operations, and consequently, adversely affect our profitability. For example, in December 2007 the U.S. BLM imposed a permitting application fee of \$4,000 per well drilled on federal lands. This fee increased our regulatory costs in 2008 by an additional \$1.0 million and affected the timing of our development of federal leases.

In addition, from time to time we may be subject to legal proceedings and claims as a result of these regulations. Please see Item 3, Legal Proceedings, for a description of material pending litigation.

We operate in a highly competitive environment and our competitors may have greater resources than us.

The natural gas and oil industry is intensely competitive and we compete with other companies, many of which are larger and have greater financial, technological, human and other resources. Many of these companies not only explore for and produce crude oil and natural gas but also carry on refining operations and market petroleum and other products on a regional, national or worldwide

basis. Such companies may be able to pay more for productive natural gas and oil properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, such companies may have a greater ability to continue exploration activities during periods of low oil and gas market prices. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. If we are unable to compete, our operating results and financial position may be adversely affected.

The coal beds from which we produce methane gas contain water that may hamper our ability to produce gas in commercial quantities.

Coal beds contain water that must be reduced in order for the gas to desorb from the coal and flow to the well bore. Where groundwater produced from our coalbed methane projects fails to meet the quality requirements of applicable regulatory agencies or our wells produce water in excess of the applicable volumetric permit limit, we may have to explore alternative methods of disposal such as re-injections or water treatment facilities. The costs to dispose of this produced water may increase if any of the following occur:

- we cannot obtain future permits from applicable regulatory agencies;
- water of lesser quality is produced;
- our wells produce excess water; or
- new laws or regulations require water to be disposed of in a different manner.

Our ability to remove and dispose of sufficient quantities of water from a coal seam will determine whether or not we can produce gas in commercial quantities from that seam. The cost of water disposal may affect our profitability.

Our coalbed methane wells typically have a shorter reserve life and lower rates of production than conventional natural gas wells, which may adversely affect our profitability during periods of low natural gas prices.

The shallow coals from which we produce natural gas in the Powder River Basin typically have a seven to eight year reserve life and have lower total reserves and produce at lower rates than most conventional natural gas wells. We depend on drilling a large number of wells each year to replace production and reserves in the Powder River Basin and to distribute operational expenses over a larger number of wells. A decline in natural gas prices could make certain wells uneconomical because production rates are lower on an individual well basis and may be insufficient to cover operational costs.

We may have difficulty managing growth in our business.

Because of our small size, growth in accordance with our business plan, if achieved, will place a significant strain on our financial, technical, operational and management resources. If we expand our activities and increase the number of projects we are evaluating or in which we participate, there will be additional demands on our financial, technical and management resources. The failure to continue to upgrade our technical, administrative, operating and financial control systems or the occurrence of unexpected expansion difficulties, including the failure to recruit and retain experienced managers, geoscientists and engineers, could have a material adverse effect on our business, financial condition and results of operations and our ability to timely execute our business plan.

Our success depends on our key management personnel, the loss of any of whom could disrupt our business.

The success of our operations and activities is dependent to a significant extent on the efforts and abilities of our management. The loss of services of any of our key managers could have a material adverse effect on our business. We have not obtained “key man” insurance for any members of our management. Mr. Peter G. Schoonmaker is our Chief Executive Officer and President, and Mr. Ronald T. Barnes is our Chief Financial Officer, Senior Vice President and Secretary. The loss of the services of either of these individuals, or other key personnel, may adversely affect our business and prospects. We currently do not have employment agreements or non-competition agreements with any of the members of our management other than Mr. Schoonmaker and Mr. Barnes.

Some of our directors may have conflicts of interest because they are also currently affiliates, directors or officers of entities that make investments in the energy sector and/or may compete with us. The resolution of these conflicts of interest may not be in our or our stockholders’ best interests.

Robert L. Cables, Jr. and Jeffrey P. Gunst, two of our directors, serve as Partner and Principal, respectively, of Avista Capital Holdings, L.P., or Avista, a private equity firm that makes investments in the energy sector. Messrs. Cables and Gunst have in the past provided consulting services to certain DLJ Merchant Banking portfolio companies through arrangements with MB Advisory Partners, LLC, an affiliate of Avista. In addition, Sylvester P. Johnson, IV serves as President, Chief Executive Officer and a director of Carrizo. F. Gardner Parker is a director of Carrizo and Susan Schnabel is a Managing Director of DLJ Merchant Banking which holds a 32.9% equity stake in us. These relationships may create conflicts of interest regarding corporate opportunities and other matters. The resolution of any such conflicts may not always be in our or our stockholders’ best interest. In addition, our certificate of incorporation limits the fiduciary duties of our directors in conflict of interest situations, among other things.

Our failure to complete and integrate future acquisitions successfully could reduce our earnings and slow our growth.

We may be unable to identify potential acquisitions or to make acquisitions on terms that we consider economically acceptable. Furthermore, there is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our strategy of completing acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Our ability to pursue our growth strategy may be hindered if we are not able to obtain such financing or regulatory approvals. The inability to effectively manage the integration of acquisitions could reduce our focus on subsequent acquisitions and current operations, which, in turn, could negatively impact our earnings and growth. Our financial position and results of operations may fluctuate significantly from period to period, based on whether or not significant acquisitions are completed in particular periods.

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

Properties we acquire may not produce as expected, may be in an unexpected condition and may subject us to increased costs and liabilities, including environmental liabilities. Although we review acquired properties prior to acquisition in a manner consistent with industry practices, even a detailed review of records and properties may not necessarily reveal existing or potential problems or permit us to become sufficiently familiar with the properties to assess fully their condition, any deficiencies, and development potential. Generally, it is not feasible to review in depth every individual property involved in each acquisition. Ordinarily, we will focus our review efforts on the higher value properties

or properties with known adverse conditions and will sample the remainder. In addition, environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken.

The coal beds from which we produce may be drained by offsetting production wells.

Our drilling locations are spaced primarily using 80-acre spacing. Producing wells located on the 80-acre spacing units contiguous with our drilling locations may drain the acreage underlying our wells. If a substantial number of productive wells are drilled on spacing units adjacent to our properties, it could have an adverse impact on the economically recoverable reserves of our properties that are susceptible to such drainage.

We may not be able to keep pace with technological developments in our industry.

The natural gas and oil industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement those new technologies at substantial cost. In addition, other natural gas and oil companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures and implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete or if we are unable to use the most advanced commercially available technology, our business, financial condition and results of operations could be materially adversely affected.

Because we are a relatively small company, we have been and expect to continue to be disproportionately negatively impacted by the cost of compliance with securities laws and regulations.

The Sarbanes-Oxley Act of 2002, or the Act, which became law in July 2002, has required changes in the corporate governance, securities disclosure and compliance practices of public companies. The SEC has promulgated rules pursuant to the Act covering a variety of subjects, including corporate governance guidelines. Compliance with these rules has significantly increased our legal, financial and accounting costs. In addition, compliance with these rules has required the dedication of a significant amount of the time of management and the board of directors and may make it more difficult for us to attract and retain qualified directors, particularly independent directors, or qualified executive officers. Because we are a small company with relatively few employees, we have been disproportionately negatively impacted by these rules and regulations.

As directed by Section 404 of the Act, the SEC adopted rules requiring public companies to include a report of management on the company's internal control over financial reporting in their annual reports on Form 10-K that contains an assessment by management of the effectiveness of the company's internal control over financial reporting. In addition, the public accounting firm auditing the company's financial statements must attest to and report on management's assessment of the effectiveness of the company's internal control over financial reporting. The requirement to include management's report first applies to this annual report. Our accounting firm will first be required to attest to and report on management's assessment in the annual report for the year ended December 31, 2009. If management is unable to conclude that we have effective internal control over financial reporting, or if our independent auditors are unable to provide us, when required, with an unqualified report as to the effectiveness of our internal control over financial reporting, investors could lose confidence in the reliability of our financial statements, which could result in a decrease in the value of our securities.

We are a small company with limited resources. The number and qualifications of our finance and accounting staff are limited, and we have limited monetary resources. We experience difficulties in attracting qualified staff with requisite expertise due to our profile and a generally tight market for staff with expertise in these areas. We retained a consultant to assist us in the process of testing and evaluating our internal control over financial reporting. A key risk is that management will not timely remediate any deficiencies that may be identified as part of the review process.

Risks Related to our Relationship with DLJ Merchant Banking and Other Initial Stockholders

Our founding stockholders have substantial influence over the outcome of certain stockholder votes and may exercise this voting power in a manner adverse to our other stockholders.

DLJ Merchant Banking beneficially owns approximately 32.9% of our outstanding common stock. Accordingly, DLJ Merchant Banking is in a position to have a substantial influence on the outcome of certain matters requiring a stockholder vote, including the election of directors and the adoption of certain amendments to our certificate of incorporation.

In addition, Carrizo beneficially owns approximately 8.3% of our outstanding common stock. This ownership, when combined with that of DLJ Merchant Banking, constitutes slightly less than a majority of our common stock and could have the effect of delaying or preventing a change in control of or otherwise discouraging a potential acquirer from attempting to obtain control of us. In addition, the interests of these stockholders may differ from those of our other stockholders, and these stockholders may vote their common stock in a manner that may adversely affect our other stockholders.

Risks Relating to Our Common Stock

The price of our common stock may be volatile and you may not be able to resell your shares at a favorable price.

The market price of our common stock may be volatile and you may not be able to resell your shares at or above the price you paid for such shares. During 2008, the closing price of our common stock ranged from a high of \$5.10 per share to a low of \$0.24 per share. The risk factors set forth in this report, among other items, could affect our stock price.

The market for purchases and sales of our common stock may be very limited, and the sale of a limited number of shares could cause the price to fall sharply.

Although our common stock is listed for trading on the NASDAQ Global Market, our securities are currently relatively thinly traded. Accordingly, it may be difficult to sell shares of common stock quickly without significantly depressing the value of the stock. Unless we are successful in developing continued investor interest in our stock, sales of our stock could continue to result in major fluctuations in the price of the stock.

We may not be able to maintain compliance with NASDAQ's continued listing requirements.

We must comply with NASDAQ's continued listing requirements in order to maintain our listing on NASDAQ's Global Market. These continued listing standards include requirements addressing the number of shares publicly held, market value of publicly held shares, stockholder's equity, number of round lot holders, and a \$1.00 minimum closing bid price. Our stock price has generally been below the \$1.00 minimum bid requirement since October 2008. Ordinarily, if a company's closing bid price is below \$1.00 for 30 consecutive trading days, it receives a notice from NASDAQ that it will be subject to delisting if it fails to regain compliance within 180 days following the date of the notice letter by maintaining a minimum bid closing price of at least \$1.00 for ten consecutive business days. However, the NASDAQ has proposed suspending the \$1.00 minimum bid requirement through July 19, 2009. If

NASDAQ reinstates the \$1.00 minimum bid price requirement as scheduled and, thereafter, the closing bid price for our common stock is below \$1.00 per share for 30 consecutive days or if we in the future fail to meet the other requirements for continued listing on the NASDAQ Global Market, then our common stock could be delisted.

In order to regain compliance with the \$1.00 minimum bid requirement, we would have to attain a stock price of at least \$1.00 per share for a minimum of 10 consecutive business days prior to the expiration of 180 days from the date of the notice letter from NASDAQ, but the NASDAQ may in its discretion require that we maintain a bid price of at least \$1.00 per share for a period in excess of 10 consecutive business days.

The delisting of our common stock would adversely affect the market liquidity for our common stock, the per share price of our common stock and impair our ability to raise capital that may be needed for future operations. Delisting from NASDAQ could also have other negative results, including the potential loss of confidence by customers and employees, the loss of institutional investor interest and fewer business development opportunities. In addition, we would be subject to a number of restrictions regarding the registration and qualification of our common stock under federal and state securities laws.

If our common stock is not eligible for quotation on another market or exchange, trading of our common stock could be conducted in the over-the-counter market or on an electronic bulletin board established for unlisted securities such as the Pink Sheets or the OTC Bulletin Board. In such event, it could become more difficult to dispose of, or obtain accurate quotations for the price of our common stock, and there would likely also be a reduction in our coverage by security analysts and the news media, which could cause the price of our common stock to decline further.

If our stock price trades below \$1.00 for a sustained period and we face delisting on the NASDAQ, we may seek to implement a reverse stock split. However, reverse stock splits frequently result in a loss in stockholder value as the actual post-split price is often lower than the pre-split price, adjusted for the split. Accordingly, a reverse stock split may not solve the listing requirement deficiency even if implemented.

The percentage ownership evidenced by the common stock is subject to dilution.

We are authorized to issue up to 100,000,000 shares of common stock and are not prohibited from issuing additional shares of such common stock. You do not have statutory “preemptive rights” and therefore are not entitled to maintain a proportionate share of ownership by buying additional shares of any new issuance of common stock before others are given the opportunity to purchase the same. Accordingly, your percentage ownership, as a holder of the common stock, will be subject to change as a result of the sale of any additional common stock or other equity interests in us.

Anti-takeover provisions in our certificate of incorporation, our bylaws and Delaware law could prohibit a change of control that our stockholders may favor and which could affect our stock price.

Provisions in our second amended and restated certificate of incorporation, our amended and restated bylaws, and applicable provisions of the Delaware General Corporation Law may make it more difficult and expensive for a third party to acquire control of us, even if a change of control would be beneficial to the interests of our stockholders. These provisions could discourage potential takeover attempts and could adversely affect the market price of our common stock. Our certificate of incorporation and bylaws:

- authorize the issuance of blank check preferred stock that could be issued by our board of directors to thwart a takeover attempt;

- classify the board of directors into staggered, three-year terms, which may lengthen the time required to gain control of our board of directors;
- prohibit cumulative voting in the election of directors, which would otherwise allow holders of less than a majority of stock to elect some directors;
- require super-majority voting by our stockholders to effect amendments to provisions of our certificate of incorporation concerning the number of directors;
- require super-majority voting by our stockholders to effect any stockholder-initiated amendment to any provision of our bylaws;
- limit who may call special meetings of our stockholders;
- prohibit stockholder action by written consent, thereby requiring all actions to be taken at a meeting of the stockholders;
- establish advance notice requirements for stockholder nominations of candidates for election to the board of directors or for stockholder proposals that can be acted upon at annual meetings of stockholders; and
- require that vacancies on the board of directors, including newly-created directorships, be filled only by a majority vote of directors then in office.

In addition, Section 203 of the Delaware General Corporation Law may discourage, delay or prevent a change in control by prohibiting us from engaging in a business combination with an interested stockholder for a period of three years after the person becomes an interested stockholder.

Because we have no plans to pay dividends on our common stock, investors must look solely to stock appreciation for a return on their investment in us.

We do not anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain all future earnings to fund the development and growth of our business. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that the board of directors deems relevant. The terms of our credit facility restrict the payment of dividends without the prior written consent of the lenders. Investors must rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize a return on their investment. Investors seeking cash dividends should not purchase our common stock.

ITEM 1B UNRESOLVED STAFF COMMENTS

None.

ITEM 3 LEGAL PROCEEDINGS

From time to time, we are subject to legal proceedings and claims that arise in the ordinary course of our business. The following represent legal actions in which we are involved. No assurance can be given that these legal actions will be resolved in our favor. However, management believes, based on its experiences to date, that these matters will not have a material adverse impact on our business, financial position or results of operations.

We, together with the State of Montana, the Montana Department of Environmental Quality, the Montana Board of Oil and Gas Conservation and the Department of Natural Resources, were named as defendants in a lawsuit (Civil Cause No. DV-05-27) filed on May 19, 2005 in the Montana 22nd Judicial District Court, Bighorn County by Diamond Cross Properties, LLC relating to the Coal

Creek POD. The plaintiff is a surface owner of Diamond Cross Ranch located in Big Horn County and Rosebud County, Montana where we have a lease for approximately 10,300 acres, serve as operator and own a working interest in the minerals under lease. The plaintiff sought to permanently enjoin the State of Montana and its administrative bodies from issuing licenses or permits, or authorizing the removal of ground water from under the plaintiff's ranch. In addition, the plaintiff further sought to preliminarily and permanently enjoin us on the basis that our operations lacked adequate safeguards required under the Montana state constitution. On August 25, 2005, the district court issued an order denying without prejudice the application for temporary restraining order and preliminary injunction requested by the plaintiff. The case was appealed by the plaintiff to the Montana Supreme Court. On November 16, 2005, the Montana Supreme Court issued an order that denied enjoining the Coal Creek POD, and subsequently, the Montana Supreme Court remanded the case back to the district court for a decision on the merits.

We, together with the defendants above, were also named as defendants in a lawsuit (Civil Cause No. DV-05-70) filed on September 21, 2005 in the Montana 22nd Judicial District Court, Bighorn County by Diamond Cross Properties, LLC relating to the Dietz POD. The plaintiff sought similar relief as in the Coal Creek POD suit.

The two cases were combined.

On July 14, 2008, the district court issued a summary judgment order in the combined case, and the order was subsequently entered as a judgment on August 15, 2008. As a result, we have continued our operations in the two project areas. To date, there has been no appeal by the plaintiff.

In addition, like other natural gas and oil producers and marketers, our operations are subject to extensive and rapidly changing federal and state environmental, health and safety and other laws and regulations governing air emissions, wastewater discharges, and solid and hazardous waste management activities. Therefore it is extremely difficult to reasonably quantify future environmental and regulatory expenditures.

Please see Items 1 and 2, Business and Properties—Regulation—Permitting Issues for Federal Lands, regarding litigation in which we have intervened with respect to CBM production in Wyoming and Montana.

ITEM 4 SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

PART II

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

Market Information

Shares of our common stock are traded on the NASDAQ Global Market under the symbol "PINN." As of April 9, 2009, we had 29,188,009 shares of common stock outstanding held of record by approximately 60 record holders.

The following table sets forth, for the periods indicated, the high and low closing sales prices for our common stock. The last reported sales price of our common stock on April 9, 2009 was \$0.23 per share.

	Sales Price Range per Share of Common Stock	
	High	Low
Year ended December 31, 2008		
Fourth quarter	\$1.22	\$0.24
Third quarter	3.40	1.19
Second quarter	4.01	2.22
First quarter	5.10	2.55
Year ended December 31, 2007		
Fourth quarter	\$6.49	\$4.12
Third quarter	7.65	4.25
Second quarter (beginning May 15, 2007, the first trading day after pricing our initial public offering)	8.59	7.74

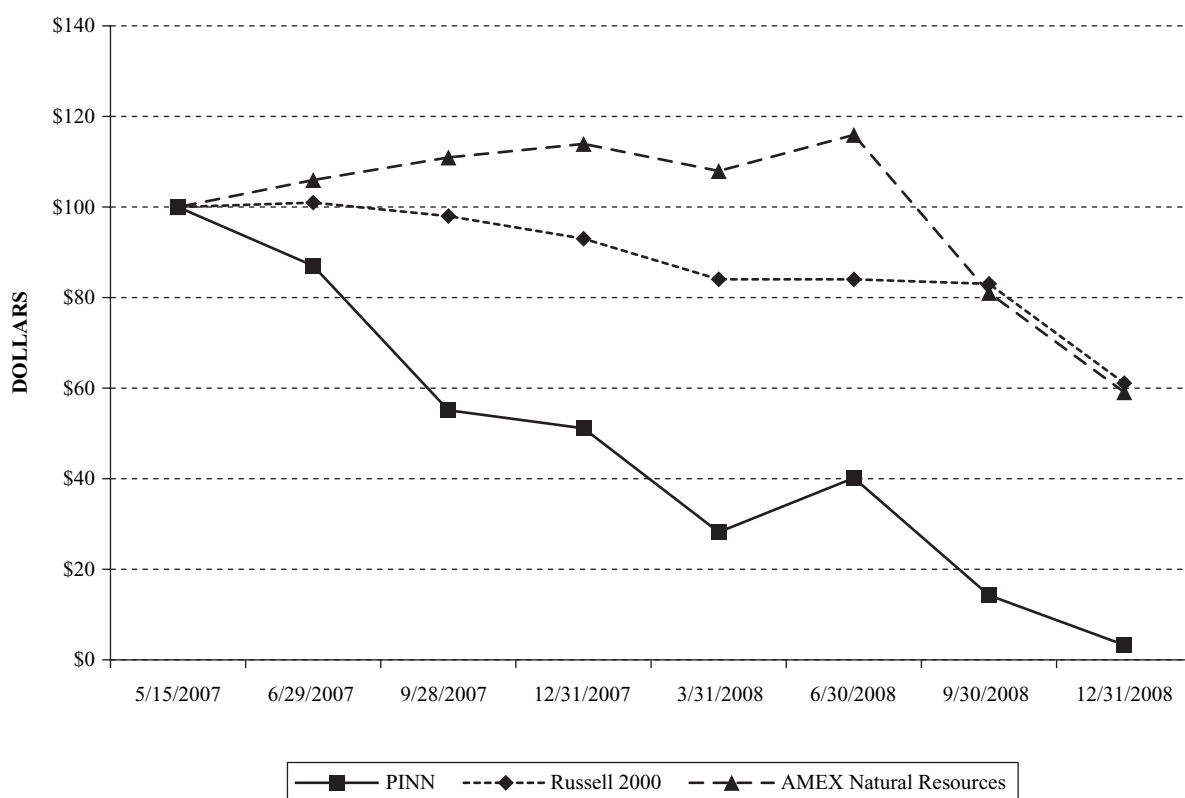
We have not paid any dividends on our common stock to date and we do not expect to pay any dividends in the foreseeable future. Our credit facility prohibits the payment of dividends to stockholders without the prior written consent of the lenders.

Performance Graph

The following graph presents a comparison of the yearly percentage change in the cumulative total return on our common stock over the period from May 15, 2007, the first trading date after pricing our initial public offering, to December 31, 2008, with the cumulative total return of the Russell 2000 Index and the American Stock Exchange (AMEX) Natural Resources Industry Index over the same period. The graph assumes that \$100 was invested on May 15, 2007 in our common stock at the closing market price at the beginning of this period and in each of the other two indices and the reinvestment of all dividends, if any.

The graph is presented in accordance with requirements of the SEC. Stockholders are cautioned against drawing any conclusions from the data contained therein, as past results are not necessarily indicative of future financial performance.

**Comparison of Cumulative Total Return
of Pinnacle Gas Resources, the Amex Natural Resources Industry Index,
and Russell 2000 Index**



Pursuant to SEC rules, the foregoing graph is not deemed “filed” with the SEC. We made no repurchases of our common stock in the fourth quarter of 2008.

	<u>5/15/2007</u>	<u>6/29/2007</u>	<u>9/28/2007</u>	<u>12/31/2007</u>	<u>3/31/2008</u>	<u>6/30/2008</u>	<u>9/30/2008</u>	<u>12/31/2008</u>
Pinnacle Gas Resources, Inc. . . .	\$100.00	87.00	55.00	51.00	28.00	40.00	14.00	3.00
Russell 2000 Index	\$100.00	101.00	98.00	93.00	84.00	84.00	83.00	61.00
AMEX Natural Resources Index .	\$100.00	106.00	111.00	114.00	108.00	116.00	81.00	59.00

ITEM 6 SELECTED FINANCIAL DATA

The following tables set forth our selected historical financial data for, and as of the end of, each of the periods indicated. Our historical results are not necessarily indicative of the results that may be expected for any future period. The selected historical financial data should be read in conjunction with Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations and our financial statements and related notes included elsewhere in this document.

	Year Ended December 31,				
	2004	2005	2006	2007	2008
(In thousands, except share and per share data)					
Statement of Operations Data:					
Revenues					
Gas sales	\$ 7,393	\$ 14,136	\$ 12,196	\$ 13,141	\$ 22,441
Income from earn-in joint venture agreement	368	1,629	379	—	—
Total revenues	<u>7,761</u>	<u>15,765</u>	<u>12,575</u>	<u>13,141</u>	<u>22,441</u>
Operating expenses					
Lease operating expenses	1,445	1,781	2,993	4,721	6,450
Production taxes	838	1,637	1,198	1,397	1,941
Marketing and transportation	1,218	1,582	1,962	3,464	4,694
General and administrative, net . . .	1,552	2,267	4,343	5,179	6,674
Depreciation, depletion, amortization and accretion	3,328	5,622	6,673	6,516	9,322
Impairment of oil and gas properties	—	—	—	18,225	21,521
Total operating expenses	<u>8,381</u>	<u>12,889</u>	<u>17,169</u>	<u>39,502</u>	<u>50,602</u>
Operating income (loss)	<u>(620)</u>	<u>2,876</u>	<u>(4,594)</u>	<u>(26,361)</u>	<u>(28,161)</u>
Other income (expense)					
Gain (loss) on derivatives(1)	(766)	(4,815)	7,362	2,211	5,762
Interest income	61	17	720	677	162
Other income	4	129	484	379	626
Unrealized derivative loss	—	—	(26)	—	—
Interest expense	(2)	(47)	(168)	(283)	(125)
Total other income (expense)	<u>(703)</u>	<u>(4,716)</u>	<u>8,372</u>	<u>2,984</u>	<u>6,425</u>
Net income (loss)	\$ (1,323)	\$ (1,840)	\$ 3,778	\$ (23,377)	\$ (21,736)
Preferred dividends, related party . .	(2,623)	(5,409)	(20,964)	—	—
Net income (loss) attributable to common stockholders	<u>\$ (3,946)</u>	<u>\$ (7,249)</u>	<u>\$ (17,186)</u>	<u>\$ (23,377)</u>	<u>\$ (21,736)</u>
Net income (loss) per common share					
Basic and diluted	\$ (0.79)	\$ (1.42)	\$ (0.87)	\$ (0.86)	\$ (0.75)
Weighted average shares outstanding					
Basic and diluted(2)	5,000,000	5,094,800	19,783,118	27,281,680	29,096,411

(1) In order to provide a measure of stability to the cash flow in an environment of volatile oil and gas prices and to manage the exposure to commodity price risk, we chose to periodically hedge a portion of our oil and gas production using swap and collar agreements. We account for our derivative instruments under the provisions of Statement of Financial Accounting Standard

No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS No. 133"). SFAS No. 133 requires us to record derivative instruments at their fair value. Our management has chosen not to use hedge accounting for these arrangements. For the years ended December 31, 2008, 2007, 2006, 2005 and 2004 we have classified the gains and losses (both realized and unrealized) on derivatives to other income/expense in the statements of operations. We feel that this presentation fairly presents revenues derived from operations because the gains and losses on derivatives are comprised of a significant unrealized gain or loss for future periods which is not reflective of current operations.

- (2) For all periods in which there was a net loss attributable to common stockholders, all of our stock options and warrants were anti-dilutive. Common stock equivalents of 676,250, 871,000, 1,035,000, 13,676,200 and 9,187,500 at December 31, 2008, 2007, 2006, 2005 and 2004, respectively, were excluded because they were anti-dilutive.

Year Ended December 31,				
2004	2005	2006	2007	2008

(In thousands)

Statement of Cash Flows Data:

Net cash provided by (used in) operating activities	\$ 1,350	\$ 8,792	\$ 6,029	\$(16,685)	\$ 7,582
Net cash used in investing activities	(14,017)	(25,301)	(63,880)	(9,423)	(26,858)
Net cash provided by financing activities	11,740	15,582	59,941	29,497	11,471

Other Financial Data:

Capital expenditures—exploration and production	\$ 13,149	\$ 20,866	\$ 62,340	\$ 14,006	\$ 27,217
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As of December 31,				
2004	2005	2006	2007	2008

(In thousands)

Balance Sheet Data:

Cash and cash equivalents	\$ 3,599	\$ 2,672	\$ 4,762	\$ 8,151	\$ 346
Property and equipment, net	43,054	63,529	127,189	125,011	123,147
Total assets	54,504	77,081	150,332	146,593	138,340
Long-term debt (including current portion)(1) . .	345	828	807	786	12,263
Total liabilities	13,817	23,897	31,503	20,756	33,061
Redeemable preferred stock(2)	18,338	31,400	—	—	—
Total stockholders' equity	22,349	21,784	118,829	125,837	105,279

- (1) Long-term debt does not include fair value of derivatives, asset retirement obligation and the long-term portion of production taxes for the year ended December 31, 2008. Debt from the credit facility of \$11.5 million is included in "Long term debt—current portion" for the year ended December 31, 2008.
- (2) On April 11, 2006, we used approximately \$53.6 million of the net proceeds from our private placement to redeem all of the outstanding shares of our Series A Redeemable Preferred Stock, all of which were held by DLJ Merchant Banking.

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

The discussion and analysis that follows should be read together with Item 6, Selected Financial Data and the accompanying financial statements and notes related thereto that are included elsewhere in this annual report. It includes forward-looking statements that may reflect our estimates, beliefs, plans and expected performance. The forward-looking statements are based upon events, risks and uncertainties that may be outside our control. Our actual results could differ significantly from those discussed in these forward-looking statements. Factors that could cause or contribute to these differences include, but are not limited to, market prices for natural gas and oil, regulatory changes, estimates of proved reserves, economic conditions, competitive conditions, development success rates, capital expenditures and other uncertainties, as well as those factors discussed below and elsewhere in this annual report, including in Item 1A, Risk Factors, all of which are difficult to predict. As a result of these assumptions, risks and uncertainties, the forward-looking matters discussed may not occur.

Overview

We are an independent energy company engaged in the acquisition, exploration and development of domestic onshore natural gas reserves. We primarily focus our efforts on the development of CBM properties located in the Powder River Basin in northeastern Wyoming and southern Montana. In addition, in April 2006, we acquired properties located in the Green River Basin in southern Wyoming. As of December 31, 2008, we owned natural gas and oil leasehold interests in approximately 477,000 gross (332,000 net) acres, approximately 90% of which were undeveloped. As of December 31, 2008, we had estimated net proved reserves of approximately 27.7 Bcf based on the year-end CIG index price of \$4.61 per Mcf.

We had a total capital expenditure budget of \$30.1 million for 2008 and expected to drill 146 gross (110 net) wells during the period. However, due to low CIG index prices, the economic climate and limited capital resources, we reduced our capital expenditure budget resulting in actual 2008 capital expenditures of \$27.8 million. In connection with our reduced capital expenditure budget, we also reduced our drilling and completion targets for 2008 and drilled 117 gross (82 net) wells. We curtailed substantially all new drilling in the fourth quarter of 2008, and have shut-in a number of wells that are not economic at current natural gas price levels. If natural gas prices remain low, we expect to continue to operate with a reduced capital expenditure plan. Under our reduced capital expenditure plan, we would generally make such expenditures only as necessary to secure drilling permits in strategic areas, drill wells that secure leasehold positions and construct the necessary infrastructure to complete and hook-up wells that have already been drilled. Our capital expenditure budget for 2009 will be dependent upon CIG index prices, our cash flows and the availability of additional capital resources.

We were formed in June 2003 as a Delaware corporation through a contribution of proved producing properties and undeveloped leaseholds by subsidiaries of Carrizo and U.S. Energy and a cash contribution from DLJ Merchant Banking.

In April 2006, we completed a private placement of 12,835,230 shares of our common stock to qualified institutional buyers, non-U.S. persons and accredited investors. In May 2007, we completed our initial public offering of 3,750,000 shares of common stock. Please see the information under the heading "Liquidity and Capital Resources—Cash Flow from Financing Activities" in this Item 7 for further information regarding issuances of equity to our initial stockholders.

Shares of our common stock are traded on the NASDAQ Global Market under the symbol "PINN."

Significant Developments

Credit Facility and Liquidity. On April 14, 2009 we and the lenders entered into the fourth amendment to the credit facility which waived compliance with the current ratio financial covenant as of December 31, 2008 and March 31, 2009 and with the restrictive covenants related to accounts payable, permitted liens and permitted debt until the next borrowing base redetermination expected in the fall of 2009, subject to certain financial caps. In connection with the waiver of the restrictive covenants, the lenders reduced our borrowing base to \$9.0 million, with further monthly reductions until the borrowing base reaches \$6.5 million on October 1, 2009. We believe that we may not be in compliance with certain restrictive covenants throughout 2009, but will seek additional waivers. There can be no assurance that we will be able to obtain such waivers or that such waivers will be obtained on acceptable terms. If we are unable to obtain future waivers and/or to comply with the restrictive covenants, the lenders could accelerate our indebtedness under the credit facility or foreclose on properties held by liens. We have remained in compliance with the payment of principal and interest pertaining to the credit facility including ensuring that our outstanding borrowings remain within the limitations of the borrowing base. Due to borrowing base limitations and waiver stipulations, we are currently unable to incur additional indebtedness under the credit facility.

In accordance with accounting guidance, we have classified all of the outstanding debt under the credit facility totaling \$11.5 million as of December 31, 2008 as a current payable because it is unlikely that we will have cured the noncompliance of certain restrictive covenants during the next 12 months. We have further reduced our outstanding indebtedness under the credit facility to \$9.0 million as of April 14, 2009 in order to be in compliance with the new borrowing base limitation.

We are actively marketing certain assets to raise additional capital and are also reviewing alternatives for raising additional capital through equity and debt financing, capital restructuring and possible mergers. We sold our high pressure gas gathering system in our Cabin Creek project area in Wyoming and our remaining interest in the Arvada project area in Wyoming in April 2009. Management believes that appropriate steps, including cost-cutting measures, are being taken to make operations sustainable in the future. Although we are pursuing various alternatives to provide additional liquidity, there is no assurance of the likelihood or timing of any of these transactions.

Economic and Natural Gas Pricing Environment. During 2008, the global economy experienced a significant downturn. The downturn, which began over concerns related to the U.S. financial markets, spread to other industries which included the energy industry. The initial affects of the downturn restricted the capital and credit markets to a degree that has not been seen in a number of decades in the United States. We have been able to partially mitigate the constraints imposed by the current economic climate through utilization of our credit facility and cash flows from operations.

The fear of global recession led to an immediate drop in demand for natural gas, primarily by industrial users, which in turn led to a significant reduction in natural gas prices. The natural gas index price in the Rocky Mountain region averaged \$7.84 per Mcf for the first eight months of 2008 but only \$3.15 per Mcf for the last four months of 2008. This 60% decrease in price has caused us to reevaluate our 2009 business plan. We have curtailed drilling except for wells that will hold significant blocks of acreage. We have reduced administrative, operating and transportation costs. Even with cost reductions and a flexible capital spending budget, the current natural gas pricing and economic environment remains challenging. We are exploring strategic alternatives to increase our capital resources.

Supplemental Environmental Impact Statement. A record of decision for the SEIS covering federal lands in the Powder River Basin in Montana was signed by the BLM on December 30, 2008. This record of decision removed the injunction on drilling on federal leases in Montana, which impacted approximately 201,000 gross (168,000 net) acres of our leasehold position. We are evaluating our future plans of development in Montana.

Critical Accounting Policies

The most subjective and complex judgments used in the preparation of our financial statements are:

- Reserve evaluation and determination;
- Estimates of the timing and cost of our future drilling activity;
- Estimates of the fair valuation of hedges in place;
- Estimates of timing and cost of asset retirement obligations;
- Estimates of the expense and timing of exercise of stock options;
- Accruals of operating costs, capital expenditures and revenue; and
- Estimates for litigation.

Oil and Gas Properties

We use the full cost method of accounting for oil and gas producing activities. Under this method, all costs associated with property acquisition, exploration and development, including costs of unsuccessful exploration, costs of surrendered and abandoned leaseholds, delay lease rentals and the fair value of estimated future costs of site restoration, dismantlement and abandonment activities, are capitalized within a cost center. Our oil and gas properties are all located within the United States, which constitutes a single cost center. We capitalize certain lease operating expenses associated with exploration and development of unevaluated oil and gas properties. No gain or loss is recognized upon the sale or abandonment of undeveloped or producing oil and gas properties unless the sale represents a significant portion of gas properties and the gain significantly alters the relationship between capitalized costs and proved gas reserves of the cost center. Expenditures for maintenance and repairs are charged to lease operating expense in the period incurred.

Depreciation, depletion and amortization of oil and gas properties is computed on the unit-of-production method based on proved reserves. Amortizable costs include estimates of future development costs of proved undeveloped reserves and asset retirement obligations. We invest in unevaluated oil and gas properties for the purpose of exploration for proved reserves. The costs of such assets, including exploration costs on properties where a determination of whether proved oil and gas reserves will be established is still under evaluation, and any capitalized interest and lease operating expenses, are included in unproved oil and gas properties at the lower of cost or estimated fair market value and are not subject to amortization. On a quarterly basis, such costs are evaluated for inclusion in the costs to be amortized resulting from the determination of proved reserves, impairments, or reductions in value. To the extent that the evaluation indicates these properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. We recorded an impairment of unevaluated properties of \$5.6 million, \$0.7 million and \$0 as of December 31, 2008, 2007, and 2006, respectively. Abandonment of unproved properties is also accounted for as an adjustment to capitalized costs related to proved oil and gas properties, with no losses recognized.

Substantially all remaining unproved property costs are expected to be developed and included in the amortization base ratably over the next three to five years. Salvage value is taken into account in determining depletion rates and is based on our estimate of the value of equipment and supplies at the time the well is abandoned. The estimated salvage value of equipment included in determining the depletion rate was \$7.3 million, \$6.4 million and \$5.7 million as of December 31, 2008, 2007, and 2006, respectively.

Under the full cost method of accounting rules, capitalized costs less accumulated depletion and related deferred income taxes may not exceed a “ceiling” value which is the sum of (1) the present

value discounted at 10% of estimated future net revenue using current costs and prices, including the effects of derivative instruments designated as cash flow hedges but excluding the future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, less any related income tax effects; plus (2) the cost of properties not being amortized, if any; plus (3) the lower of costs or estimated fair value of unproved properties; less (4) the income tax effects related to differences in the book to tax basis of oil and gas properties. This is referred to as the “full cost ceiling limitation.” If capitalized costs exceed the limit, the excess must be charged to expense. The expense may not be reversed in future periods. At the end of each quarter, we calculate the full cost ceiling limitation. At December 31, 2008, the capitalized cost of our oil and gas properties exceeded the full cost ceiling limitation by approximately \$ 21.5 million based upon a natural gas price of approximately \$4.61 per Mcf in effect at that date. An impairment of approximately \$21.5 million was therefore recorded in the fourth quarter of 2008, resulting in a total impairment for the year ended December 31, 2008 of approximately \$21.5 million. The impairment of our oil and gas properties resulted from low commodity prices in the fourth quarter of 2008. Based on the CIG index price of \$2.20 per Mcf on April 9, 2009, we would have been required to take a total impairment of approximately \$46.7 million at December 31, 2008. A decline in gas prices or an increase in operating costs or reductions in economically recoverable quantities could result in the recognition of additional impairments of our oil and gas properties in future periods.

Gas Sales

We use the sales method for recording natural gas sales. Sales of gas applicable to our interest in producing natural gas and oil leases are recorded as revenues when the gas is metered and title transferred pursuant to the gas sales contracts covering our interest in gas reserves. During such times as our sales of gas exceed our pro rata ownership in a well, such sales are recorded as revenues unless total sales from the well have exceeded our share of estimated total gas reserves underlying the property at which time such excess is recorded as a gas imbalance liability. At December 31, 2008, 2007 and 2006, no such liability was recorded. Although there was no liability recorded for prior periods, gas reserves are an estimate and are updated on an annual and interim basis. Gas pricing, expenses and production may impact future gas reserves remaining which in turn, could impact the recording of liabilities in the future. Gas sales accruals at December 31, 2008, 2007 and 2006 were based on the actual volume statements from our purchasers and distribution process. If accruals were to change by 10% at year end, the impact would have been a \$209,000 change for 2008, a \$306,000 change for 2007 and a \$319,000 change for 2006.

Asset Retirement Obligations

We follow the provisions of Statement of Financial Accounting Standards (SFAS) No. 143, “Accounting for the Asset Retirement Obligations.” SFAS No. 143 generally applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. SFAS No. 143 requires us to recognize an estimated liability for costs associated with the abandonment of our oil and gas properties.

A liability for the fair value of an asset retirement obligation with a corresponding increase to the carrying value of the related long-lived asset is recorded at the time a well is completed or acquired. The increased carrying value is depleted using the units-of-production method, and the discounted liability is increased through accretion over the remaining life of the respective oil and gas properties.

The estimated liability is based on historical gas industry experience in abandoning wells, including estimated economic lives, external estimates as to the cost to abandon the wells in the future and federal and state regulatory requirements. Our liability is discounted using our best estimate of our credit-adjusted risk-free rate. Revisions to the liability could occur due to changes in estimated abandonment costs, changes in well economic lives or if federal or state regulators enact new

requirements regarding the abandonment of wells. For example, a 10% change in our estimated retirement costs would have a \$337,000 effect on our asset retirement obligation liability at December 31, 2008.

The following is a summary of our asset retirement obligation activity for the years ended December 31, 2008 and 2007 (in thousands):

	Year Ended December 31,	
	2008	2007
Beginning balance of asset retirement obligations	\$2,767	\$2,321
Additional obligations added during the period	399	239
Obligations settled during the period	(48)	(1)
Revisions in estimates	—	—
Accretion expense	248	208
Ending balance of asset retirement obligations	<u>\$3,366</u>	<u>\$2,767</u>

Inventory

We have acquired inventory of oil and gas equipment, primarily tubulars, to take advantage of quantity pricing and to secure a readily available supply. Inventory is valued at the lower of average cost or market. Inventory is used in the development of gas properties and to the extent it is estimated that it will be billed to other working interest owners during the next year, it is included in current assets. Otherwise, it is recorded in non-current assets. The price of steel is a primary factor in valuing our inventory. Under the valuation method of lower of average cost or market, a 10% reduction in the price of steel would have caused a \$47,000 reduction in our inventory valuation as of December 31, 2008. The market price of steel is evaluated each quarter using prices quoted by authorized vendors in the area.

Property and Equipment

Property and equipment is comprised primarily of a building, computer hardware and software, vehicles and equipment, and is recorded at cost. Renewals and betterments that substantially extend the useful lives of the assets are capitalized. Maintenance and repairs are expensed when incurred. Depreciation and amortization are provided using the straight-line method over the estimated useful lives of the assets, ranging as follows: buildings—30 years, computer hardware and software—3 to 5 years, machinery, equipment and vehicles—5 years, and office furniture and equipment—3 to 5 years.

Long-Lived Assets

Long-lived assets to be held and used in our business are reviewed for impairment whenever events or changes in circumstances indicate that the related carrying amount may not be recoverable. When the carrying amounts of long-lived assets exceed the fair value, which is generally based on discounted expected future cash flows, we record an impairment. No impairments were recorded during the years ended December 31, 2008, 2007 and 2006.

General and Administrative Expenses

General and administrative expenses are reported net of amounts allocated and billed to working interest owners of gas properties operated by us. The administrative expenses billed to working interest owners may change in accordance with the terms of the joint operating agreements. Administrative expenses are charged to working interest owners based on productive well counts. A 10% change in well counts for the year ended December 31, 2008 would have increased or decreased our expenses

billed to working interest owners by approximately \$184,000. As we operate and drill additional wells in the future, additional administrative expenses will be charged to the working interest owners when the wells become productive. General and administrative expenses for the year ended December 31, 2008 also include \$2.1 million of merger related costs attributable to the failed merger with Quest Resource Corporation.

Income Taxes

We use the asset and liability method of accounting for income taxes, in accordance with SFAS No. 109, "Accounting for Income Taxes." Deferred tax assets and liabilities are recognized for the expected future tax consequences of temporary differences between the financial statement and tax bases of assets and liabilities. If appropriate, deferred tax assets are reduced by a valuation allowance which reflects expectations of the extent to which such assets will be realized. As of December 31, 2008, 2007 and 2006, we had recorded a full valuation allowance for our net deferred tax asset.

On January 1, 2007, we adopted the Financial Accounting Standards Board Interpretation No. 48, "Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109" (FIN 48). FIN 48 prescribes a measurement process for recording in the financial statements uncertain tax positions taken or expected to be taken in a tax return. FIN 48 requires that we recognize in our consolidated financial statements only those tax positions that are "more-likely-than-not" of being sustained as of the adoption date, based on the technical merits of the position. As a result of the implementation of FIN 48, we performed a comprehensive review of our material tax positions in accordance with recognition and measurement standards established by FIN 48.

As a result of this review, we did not identify any material deferred tax assets that required adjustment. As of December 31, 2008 and 2007 we had not recorded any material uncertain tax benefits.

Our policy is to recognize interest and penalties related to uncertain tax benefits in income tax expense. As of December 31, 2008, 2007 and 2006, we have not recognized any interest or penalties in our statement of operations or statement of financial position.

We are subject to the following material taxing jurisdictions: U.S. federal. We also have material operations in the state of Wyoming; however, Wyoming does not impose a corporate income tax. The tax years that remain open to examination by the U.S. Internal Revenue Service are years 2004 through 2008. Due to our net operating loss carry forwards, the Internal Revenue Service may also adjust the amount of loss realizable under examination back to 2003.

Derivatives

We use derivative instruments to manage our exposure to fluctuating natural gas prices through the use of natural gas swap and option contracts. We account for derivative instruments or hedging activities under the provisions of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 requires us to record derivative instruments at their fair value. If the derivative is designated as a fair value hedge, the changes in the fair value of the derivative and of the hedged item attributable to the hedged risk are recognized in earnings. If the derivative is designated as a cash flow hedge, the effective portions of changes in the fair value of the derivative are recorded in other comprehensive income (loss) and are recognized in the statement of operations when the hedged item affects earnings. Ineffective portions of changes in the fair value of cash flow hedges, if any, are recognized in earnings. Changes in the fair value of derivatives that do not qualify for hedge treatment are recognized in earnings. Please see Note 6 of the notes to our audited financial statements appearing elsewhere in this annual report for additional discussion of derivatives.

We periodically hedge a portion of our oil and gas production through swap and collar agreements. The purpose of the hedges is to provide a measure of stability to our cash flows in an environment of volatile oil and gas prices and to manage the exposure to commodity price risk. Our management decided not to use hedge accounting for these agreements. Therefore, in accordance with the provisions of SFAS No. 133, the changes in fair market value are recognized in earnings.

Stock-Based Compensation

Effective January 1, 2006, we adopted SFAS No. 123(R), “Share-Based Payments,” which requires companies to recognize compensation expense for share-based payments based on the estimated fair value of the awards. SFAS No. 123(R) also requires that the benefits of tax deductions in excess of compensation cost recognized for stock awards and options (“excess tax benefits”) be presented as financing cash inflows in the statement of cash flows.

Under SFAS No. 123(R), compensation expense for all share-based payments granted subsequent to January 1, 2006, based on the estimated grant date fair value, has been recorded in each of the years ended December 31, 2008, 2007 and 2006. We record compensation expense related to non-employees under the provisions of SFAS No. 123 and Emerging Issues Task Force EITF 96-18 “Accounting for Equity Instruments that are Issued to Other than Employees for Acquiring, or in conjunction with Selling Goods or Services” and recognize compensation expense over the vesting periods of such awards.

As required by SFAS No. 123, as amended by SFAS No. 148, “Accounting for Stock-Based Compensation—Transition and Disclosure,” we have computed the fair value of options granted using the Black-Scholes option pricing model. In order to calculate the fair value of the options, certain assumptions are made regarding components of the model, including risk-free interest rate, volatility, expected dividend yield, and expected option life. Changes to the assumptions could cause significant adjustments to valuation. For options granted before January 1, 2006, expected volatility was not considered because we were a private company at the grant date of these options. For stock option grants after January 1, 2006, we used a volatility rate of 35% and began to include estimated forfeiture rates. We estimated the volatility rate of our common stock at the date of the grant based on the historical volatility of comparable companies. We factored in expected retention rates combined with vesting periods to determine the average expected life. The risk-free interest rate is based on the U.S. Treasury yield curve in effect at the time of the grant. No options were granted during the year ended December 31, 2008.

	Year Ended December 31,		
	2008	2007	2006
Expected Volatility	N/A	35%	35%
Dividend Yield	N/A	—	—
Risk Free Interest Rate	N/A	4.79% to 4.80%	4.30% to 5.03%
Weighted Average Expected Life (in years)	N/A	5	5

Accounts Receivable

Our revenue producing activities are conducted primarily in Wyoming. We grant credit to qualified customers, which potentially subjects us to credit risk resulting from, among other factors, adverse changes in the industry in which we operate and the financial condition of our customers. We continuously monitor collections and payments from our customers and, if necessary, record an allowance for doubtful accounts based upon historical experience and any specific customer collection issues identified. We recorded an allowance of \$100,000 as of December 31, 2008 and 2007, respectively.

Transportation Costs

We account for transportation costs under Emerging Issues Task Force Issues 00-10, "Accounting for Shipping and Handling Fees and Costs," whereby amounts paid for transportation are classified as operating expenses.

Legal Estimates

From time to time, we are subject to legal proceedings and claims that arise in the ordinary course of business. We account for these costs under SFAS No. 5, "Accounting for Contingencies," which states that a loss contingency be recorded if it is probable that a liability has been incurred and it is reasonably estimatable. At December 2008, 2007 and 2006, we recorded \$0, \$0 and \$500,000 respectively, for legal proceedings.

Per Share Information

Basic earnings (loss) per share is computed by dividing net income (loss) from continuing operations attributable to common stock by the weighted average number of common shares outstanding during each period. Diluted earnings per share is computed by adjusting the average number of common shares outstanding for the dilutive effect, if any, of common stock equivalents such as stock options and warrants. Diluted net loss per share is the same as basic net loss per share for all periods presented because potential common stock equivalents were anti-dilutive. For all periods in which there was a net loss attributable to stockholders, all of our stock options and warrants were anti-dilutive. Common stock equivalents of 676,250, 871,000 and 1,035,000 at December 31, 2008, 2007, and 2006, respectively, were excluded because they were anti-dilutive due to the net loss attributable to stockholders incurred in such periods.

Recent Accounting Pronouncements

For information concerning recent accounting pronouncements, please see Note 1 of the notes to the audited financial statements appearing elsewhere in this report.

Trends Affecting Our Business

The continued credit crisis and related turmoil in the global financial system have had an adverse impact on our business and financial condition. In addition, prices of oil and natural gas have dropped significantly at the end of 2008. As a result of low CIG index prices, the economic climate and limited capital resources, we reduced our 2008 capital expenditure budget and drilling and completion targets. We curtailed substantially all new drilling in the fourth quarter of 2008, and shut-in a number of non-economic wells. If natural gas prices remain low, we expect to continue to operate with a reduced capital expenditure plan. Under such plan, we would generally make such expenditures only as necessary to secure drilling permits in strategic areas, drill wells that secure leasehold positions and construct the necessary infrastructure to complete and hook-up wells that have already been drilled.

We have also experienced increasing costs since our inception in 2003 due to increased demand for oilfield products and services. The cyclical nature of the natural gas industry causes fluctuations in demand for goods and services from oilfield companies, suppliers and others associated with the industry, which in turn affects the prices for those goods and services. Typically, as prices for natural gas increase, so do all the costs associated with natural gas production. The decline in natural gas prices and the general economy, beginning in the fourth quarter of 2008, have curtailed drilling and development of coalbed methane properties in our area. The resulting decrease in demand for drilling rigs, cement, and tubulars has resulted in a decrease in the cost of these goods and services.

Historically, natural gas prices have been extremely volatile, and we expect that volatility to continue. For example, during the year ended December 31, 2008, the NYMEX natural gas index price ranged from a high of \$13.58 per MMBtu to a low of \$5.29 per MMBtu, while the CIG natural gas index price ranged from a high of \$10.26 per MMBtu to a low of \$1.00 per MMBtu. During the year ended December 31, 2007, the NYMEX natural gas index price ranged from a high of \$8.64 per MMBtu to a low of \$5.38 per MMBtu, while the CIG natural gas index price ranged from a high of \$7.11 per MMBtu to a low of \$0.06 per MMBtu. Changes in natural gas pricing have impacted our revenue streams, production taxes, prices used in reserve calculations, borrowing base calculations and the carrying value of our properties and the valuation of potential property acquisitions. During the years ended December 31, 2008, 2007 and 2006, estimated future gas prices had an impact on both our revenues and the costs attributable to our future operations. We expect that changing natural gas prices will continue to impact our operations and financial results in the future.

Transportation of natural gas and access to throughput capacity have a direct impact on natural gas prices in the Rocky Mountain region, where our operations are concentrated. As drilling activity increases throughout the Rocky Mountain region, additional production may come on line, which could cause bottlenecks or capacity constraints. Generally speaking, a surplus of natural gas production relative to available transportation capacity has a negative impact on prices. Conversely, as capacity increases, and bottlenecks are eliminated, prices generally increase. Although there is currently adequate transportation capacity out of the Powder River Basin, a surplus of natural gas arriving at key marketing hubs from the Powder River Basin and elsewhere relative to available takeaway capacity from these hubs has caused Rocky Mountain gas to generally trade at a discount to the NYMEX natural gas index price. For example, from January 1, 2008 through December 31, 2008, Rocky Mountain gas traded at a differential to the NYMEX natural gas index price that ranged from a premium of \$0.17 to a discount of \$6.26, with an average differential of a discount of \$2.45. The Rockies Express Pipeline which was completed and placed into service in early 2008, has increased takeaway capacity by approximately 1.5 Bcf per day from these hubs. We expect that the completion of additional proposed pipelines will help reduce the differential between gas produced in the Rocky Mountain region and the NYMEX natural gas index price. Additional proposed pipelines are scheduled to be completed in late 2010 and 2011. General economic conditions and the future demand for natural gas may change the development schedule of proposed pipelines.

Results of Operations

Net loss attributable to stockholders for the year ended December 31, 2008 was \$21.7 million, or \$0.75 per diluted share, on total revenues of \$22.4 million. Other income for the year ended December 31, 2008 included a \$3.8 million unrealized gain associated with the change in the fair valuation of our natural gas hedges in place in accordance with the provisions of SFAS No. 133. Absent such change in the valuation of hedges, we would have shown a loss of \$25.5 million. This compares to a net loss attributable to stockholders of \$23.4 million for the year ended December 31, 2007 on total revenue of \$13.1 million. Adjusted for an unrealized loss in the fair valuation of our natural gas hedges in place of \$2.3 million shown in other income, our results for the year ended December 31, 2007 would have been a net loss attributable to common stockholders of \$21.1 million.

In order to provide a measure of stability to the cash flow in an environment of volatile oil and gas prices and to manage the exposure to commodity price risk, we chose to periodically hedge a portion of our oil and gas production using swap and collar agreements. We account for our derivative instruments under the provisions of SFAS No. 133. SFAS No. 133 requires us to record derivative instruments at their fair value. Management has chosen not to use hedge accounting for these arrangements. Therefore, in accordance with SFAS No. 133, changes in the fair market value are recognized in earnings.

For the year ended December 31, 2006, the gains and losses (both realized and unrealized) on derivatives were reported in “total revenues” in the statements of operations. For the years ended December 31, 2008, 2007 and 2006, we have reclassified the gains and losses (both realized and unrealized) on derivatives to other income/expense in the statements of operations. We believe that this presentation more fairly presents revenues derived from operations because the gains and losses on derivatives are comprised of a significant unrealized gain or loss for future periods which is not reflective of current operations.

Year Ended December 31, 2008 Compared To Year Ended December 31, 2007

Gas sales volume.

Gas sales volume increased 15% from 3,389 MMcf in the year ended December 31, 2007 to 3,881 MMcf in the year ended December 31, 2008. Daily sales volume averaged 10.6 MMcf for the year ended December 31, 2008 as compared to 9.3 MMcf for the year ended December 31, 2007, a 1.3 MMcf per day increase. The increase was primarily due to production coming online in our Cabin Creek, Kirby and Deer Creek project areas. Although volumes increased in 2008 overall, our volumes were reduced by approximately 1.3 MMcf per day from September 1, 2008 through December 31, 2008 due to low natural gas pricing, weather interruptions and pipeline flow interruptions due to hydrostatic testing.

Gas sales revenue.

Revenue from gas sales increased \$9.3 million in the year ended December 31, 2008 to \$22.4 million, a 71% increase compared to the year ended December 31, 2007. This increase was primarily due to an increase in the average realized price per Mcf during the first three quarters of 2008, compared to average prices in 2007, along with increased gas sales volume. The average realized price per Mcf increased 49%, from \$3.88 per Mcf in the year ended December 31, 2007 to \$5.78 per Mcf in the year ended December 31, 2008.

Derivatives.

For the year ended December 31, 2008, we had an unrealized gain of \$3.8 million compared to an unrealized loss of \$2.3 million for the year ended December 31, 2007. The unrealized gain is noncash income based primarily on the Black-Scholes model for valuing future cash flows utilizing price volatility with a normal discount rate for our costless collars in place and an intrinsic model for our swaps in place. Hedges settled in the year ended December 31, 2008 resulted in a realized gain of \$2.0 million compared to hedge gains of \$4.5 million in the year ended December 31, 2007. The hedge gains were primarily due to the fact that gas prices were lower than our weighted average floor price of our hedges in place.

Lease operating expenses.

Lease operating expenses increased \$1.7 million in the year ended December 31, 2008 to \$6.5 million, a 37% increase compared to the year ended December 31, 2007. This increase resulted from an increase in the number of wells in the productive cycle during 2008, along with a workover program which replaced or repaired pumps, increased generator rental and diesel fuel costs, and increased water treatment costs in our Cabin Creek area. On an Mcf basis, lease operating expenses increased 19% from \$1.39 per Mcf in the year ended December 31, 2007 to \$1.66 per Mcf in the year ended December 31, 2008. The increase per Mcf was primarily due to a number of wells being in the early stages of their productive life cycle as production did not increase proportionately to the number of wells coming online. Increases in generator rental and associated fuel costs while waiting on permanent power and increased water management costs associated with water treatment in our Cabin Creek area also contributed to our higher lease operating expenses.

Production taxes.

Production taxes increased \$0.5 million in the year ended December 31, 2008 to \$1.9 million, a 39% increase from the year ended December 31, 2007. The increase in production taxes was directly correlated to gross sales revenue because production taxes in Wyoming and Montana are based on a percentage of sales value. The percentage averages 11% to 13%, depending on rates in effect for the respective year in Wyoming and 9% in Montana. The increase in production taxes was partially offset by a surplus of ad valorem taxes over-withheld from 2004 through 2006 based on the estimated mill levy rate compared to the actual rate. On an Mcf basis, production taxes were \$0.50 per Mcf for the year ended December 31, 2008 and \$0.41 per Mcf for the year ended December 31, 2007, a 21% increase, which correlates to the increase in the price per Mcf received in 2008 from 2007 partially offset by the ad valorem tax surplus netted against the expense.

Marketing and transportation.

Marketing and transportation expenses increased \$1.2 million in the year ended December 31, 2008 to \$4.7 million, a 36% increase from the year ended December 31, 2007. The increase related primarily to the increased sales volume in 2008 together with a slight increase in transportation fees and compression due to inflationary adjustments in the applicable contracts along with additional compression, which enabled us to move gas on additional high-pressure transportation systems and fees for compression design capacity which was not used. On an Mcf basis, marketing and transportation expenses increased 18% to \$1.21 per Mcf in the year ended December 31, 2008 from \$1.02 per Mcf in the year ended December 31, 2007.

General and administrative expenses, net.

General and administrative expenses are offset by operating income from drilling and production activities for which we can charge an overhead fee to nonoperating working interest owners. These well operating overhead fees were \$1.8 million in the year ended December 31, 2008, a 18% increase. General and administrative expenses, net increased \$1.5 million in the year ended December 31, 2008 to \$6.7 million from \$5.2 million in the year ended December 31, 2007. This increase was due primarily to a \$2.1 million charge related to merger costs attributable to the failed Quest Resource Corporation merger, which was partially offset by cost saving measures, including staff reductions, that we implemented in late 2008. On an Mcf basis, general and administrative expenses, net increased 13%, from \$1.53 per Mcf in the year ended December 31, 2007 to \$1.72 per Mcf in the year ended December 31, 2008. Absent the \$2.1 million merger related charges, general and administrative expenses would have been \$0.99 per Mcf for the year period ended December 31, 2008.

Depreciation, depletion, amortization and accretion.

Depreciation, depletion, amortization and accretion expense increased \$2.8 million for the year ended December 31, 2008 to \$9.3 million, a 43% increase compared to the year ended December 31, 2007. This increase was due to an increase in capital expenditures that were added into the full cost pool used for the computation of depletion, as well as increased production. On an Mcf basis, the depreciation, depletion, amortization and accretion rate increased 25% to \$2.40 per Mcf in the year ended December 31, 2008 from \$1.92 per Mcf in the year ended December 31, 2007.

Impairment.

At December 31, 2008, the capitalized cost of our oil and gas properties exceeded the full cost ceiling limitation by approximately \$21.5 million based upon a natural gas price of approximately \$4.61 per Mcf (based on the CIG index) in effect at that date. The full impairment was taken in the fourth quarter of 2008. This compares to a \$18.2 million impairment which was primarily taken in the first

quarter of 2007. For further information regarding this impairment, please see Note 1 in the notes to the audited financial statements appearing elsewhere in this report. A decline in natural gas prices or an increase in operating costs subsequent to the measurement date or reductions in economically recoverable quantities could result in the recognition of additional impairments of our oil and gas properties in future periods.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

Gas sales volume.

Gas sales volume increased 40%, from 2,413 MMcf in the year ended December 31, 2006 to 3,389 MMcf in the year ended December 31, 2007. Daily sales volume averaged 9.3 MMcf for the year ended December 31, 2007 as compared to 6.6 MMcf for the year ended December 31, 2006, a 2.7 MMcf per day increase. The increase was primarily due to production coming online in our Cabin Creek, Kirby and Deer Creek project areas.

Gas sales revenue.

Revenue from gas sales increased \$0.9 million during the year ended December 31, 2007, to \$13.1 million, an 8% increase compared to the year ended December 31, 2006. This increase was primarily due to an increase in gas sales volume which was partially offset by a decrease in the average realized price per Mcf. The average realized price per Mcf decreased 23%, from \$5.05 per Mcf in the year ended December 31, 2006 to \$3.88 per Mcf in the year ended December 31, 2007.

Derivatives.

For the year ended December 31, 2007, we had an unrealized loss of \$2.3 million compared to an unrealized gain of \$6.7 million for the year ended December 31, 2006. The unrealized loss is a noncash expense based primarily on the Black-Scholes model for valuing future cash flows utilizing price volatility with a normal discount rate. Hedges settled in the year ended December 31, 2007 resulted in a realized gain of \$4.5 million compared to a hedge gain of \$0.7 million in the year ended December 31, 2006. The hedge gains were primarily due to the fact that gas prices were lower than the weighted average floor price of our hedges in place.

Lease operating expenses.

Lease operating expenses increased \$1.7 million in the year ended December 31, 2007 to \$4.7 million, a 58% increase compared to the year ended December 31, 2006. This increase resulted from an increase in the number of wells in the productive cycle during the year ended December 31, 2007. On an Mcf basis, lease operating expenses increased 12% from \$1.24 per Mcf in the year ended December 31, 2006 to \$1.39 per Mcf in the year ended December 31, 2007. The increase per Mcf was primarily due to a number of wells being in the early stages of their productive life cycle as production did not increase proportionately to the number of wells coming online. Increases in generator rental and associated fuel costs while waiting on permanent power and increased water management costs associated with water treatment also contributed to our higher operating expenses.

Production taxes.

Production taxes increased \$0.2 million in the year ended December 31, 2007 to \$1.4 million, a 17% increase from the year ended December 31, 2006. Production taxes generally correlate to gross sales revenue because production taxes are based on a percentage of sales value. In Wyoming, the percentage averages 11% to 13%, depending on rates in effect for the respective year. The increase in production taxes for the year ended December 31, 2007 was primarily due to increased revenues associated with increased volume and a slight increase in county tax rates in Wyoming. On an Mcf

basis, production taxes were \$0.41 per Mcf for the year ended December 31, 2007 and \$0.50 per Mcf for the year ended December 31, 2006, an 18% decrease, which correlates to the decrease in the price per Mcf received in the year ended December 31, 2007 from the year ended December 31, 2006.

Marketing and transportation.

Marketing and transportation expenses increased \$1.5 million in the year ended December 31, 2007 to \$3.5 million, a 77% increase from the year ended December 31, 2006. The increase related primarily to increased sales volume in the year ended December 31, 2007, together with a slight increase in transportation fees and compression due to inflationary adjustments in the contracts along with fees paid for compression design capacity which was not used. On an Mcf basis, marketing and transportation expenses increased 26% to \$1.02 per Mcf in the year ended December 31, 2007 from \$0.81 per Mcf in the year ended December 31, 2006.

General and administrative expenses, net.

General and administrative expenses are offset by operating income from drilling and production activities for which we can charge an overhead fee to nonoperating working interest owners. These well operating overhead fees increased 27% to \$1.6 million in the year ended December 31, 2007, from \$1.2 million in the year ended December 31, 2006, due to increased productive wells which we operate and for which we charge an overhead fee. General and administrative expenses, net increased \$0.8 million in the year ended December 31, 2007 to \$5.2 million from \$4.3 million in the year ended December 31, 2006. This increase was due primarily to an increase in payroll expenses due to the hiring of additional employees during the year ended December 31, 2007. On an Mcf basis, general and administrative expenses, net decreased 15% from \$1.80 per Mcf in the year ended December 31, 2006 to \$1.53 per Mcf in the year ended December 31, 2007.

Depreciation, depletion, amortization and accretion.

Depreciation, depletion, amortization and accretion expense decreased \$0.2 million for the year ended December 31, 2007 to \$6.5 million, a 2% decrease compared to the year ended December 31, 2006. This decrease was due to a decrease in the full cost pool due to the impairments recorded in 2007 coupled with higher year-end reserves at December 31, 2007 compared to December 31, 2006. On an Mcf basis, the depreciation, depletion, amortization and accretion rate decreased 31% to \$1.92 per Mcf in the year ended December 31, 2007 from \$2.77 per Mcf in the year ended December 31, 2006.

Impairment.

At December 31, 2007, the full cost ceiling of our oil and gas properties exceeded the capitalized cost basis by approximately \$10.6 million, based upon a natural gas price of approximately \$6.04 per Mcf in effect at that date. An impairment was recorded for the nine months ended September 30, 2007 of approximately \$18.2 million, resulting in a total impairment for the year ended December 31, 2007 of approximately \$18.2 million. The impairment of our oil and gas properties resulted from low commodity prices throughout the year. For further information regarding this impairment, please see Note 1 of the notes to our audited financial statements appearing elsewhere in this report.

Liquidity and Capital Resources

In the past, our primary sources of liquidity have been private and public sales of our equity securities, cash provided by operating activities, and debt financing. All of these sources have been negatively impacted by the current economic climate, its impact on our industry, and by significant

fluctuations in oil and gas prices, operating costs, and volumes produced. We have no control over the market prices for oil and natural gas, although we are able to influence the amount of our net realized revenues related to gas sales through the use of derivative contracts. A decrease in market prices would reduce expected cash flow from operating activities and could reduce the borrowing base of our credit facility as well as the value of assets we might consider selling. Historically, decreases in market prices have limited our industry's access to the capital markets. During these challenging times, we have reduced our administrative, operating and transportation costs. We are also actively marketing asset sales and exploring other strategic alternatives and capital restructuring options.

Sales of Equity. In April 2006, we completed a private placement of an aggregate of 12,835,230 shares of our common stock at a price per share of \$11.00, or \$10.23 net of the initial purchaser's discount and placement fee. In May 2007, we completed an initial public offering of an aggregate of 3,750,000 shares of our common stock at a price per share of \$9.00, or \$8.37 net of the underwriters' discounts and commissions. Please see the information under the heading "Cash Flow from Financing Activities" in this Item 7.

Credit Facility. Effective February 12, 2007, we entered into a credit facility which permits borrowings up to the borrowing base as designated by the administrative agent. As of December 31, 2008 and March 31, 2009, we had \$11.5 million and \$10.5 million, respectively, of debt outstanding under the facility. As described below, we are currently unable to borrow additional amounts under the credit facility due to covenant limitations and may be further limited in the future based on borrowing base limitations.

As of December 31, 2008, the borrowing base under the credit facility was approximately \$13.2 million. The borrowing base was subject to automatic reductions of approximately \$666,667 per month until it reached \$10.5 million on April 1, 2009. As of April 13, 2009, our borrowing base was reduced to \$9.0 million, subject to automatic reductions of \$500,000 per month until it reaches \$6.5 million on October 1, 2009 where it will remain until the next borrowing base redetermination. If natural gas prices do not improve, we expect that our borrowing base could be further reduced in the future.

The borrowing base is determined on a semi-annual basis and at such other additional times, up to twice yearly, as may be requested by either us or the administrative agent and is determined by the administrative agent in accordance with customary practices and standards for loans of a similar nature, although such determination is at the administrative agent's discretion as the credit agreement does not provide a specific borrowing base formula.

Borrowings under this credit facility may be used solely to acquire, explore or develop oil and gas properties and for general corporate purposes. The credit facility matures February 12, 2011.

Our obligations under the credit facility are secured by liens on (i) no less than 90% of the net present value of the oil and gas to be produced from our oil and gas properties that are included in the borrowing base determination, calculated using a discount rate of 10% per annum and reserve estimates, prices and production rates and costs, (ii) options to lease, seismic options, permits, and records related to such properties, and (iii) seismic data.

Borrowings under our credit facility, as amended, bear interest either: (i) at the greater of the one month London interbank offered rate, or LIBOR, plus 1.00% or a domestic bank rate, plus in either case an applicable margin of 0.75% to 1.75% based on utilization, or (ii) on a sliding scale from the one, two, three or six month LIBOR, plus an applicable margin of 2.00% to 3.00% based on utilization. The credit agreement provides for various fees, including a quarterly commitment fee of 0.5% per annum and engineering fees to the administrative agent in connection with a borrowing base determination. In addition, the credit facility provided for an up front fee of \$27,000, which was paid on the closing date of the credit facility, and an additional arrangement fee of 1% based on utilization.

Borrowings under this credit facility may be prepaid without premium or penalty, except on Eurodollar advances.

The credit agreement, as amended, contains covenants that among other things restrict our ability (subject to certain exceptions) to do the following:

- incur liens;
- incur debt;
- make investments in other persons;
- declare dividends or redeem or repurchase stock;
- engage in mergers, acquisitions, consolidations and asset sales or amend our organizational documents;
- enter into certain hedging arrangements;
- amend material contracts; and
- enter into related party transactions.

With regard to hedging arrangements, our credit agreement provides that acceptable commodity hedging arrangements cannot cover greater than 80 to 85%, depending on the measurement date, of our monthly production from our hydrocarbon properties that are used in the borrowing base determination, and that the fixed or floor price of our hedging arrangements must be equal to or greater than the gas price used by the lenders in determining the borrowing base.

The credit agreement, as amended, also requires that we satisfy certain affirmative covenants, meet certain financial tests, maintain certain financial ratios and make certain customary indemnifications to lenders and the administrative agent. The financial covenants include requirements to maintain: (i) a ratio of EBITDA to cash interest expense of not less than 3.00 to 1.00, (ii) a ratio of current assets to current liabilities of not less than 1.00 to 1.00, (iii) a total debt to annualized EBITDA ratio of not more than 3.0 to 1.0, (iv) a quarterly total senior debt to annualized EBITDA ratio equal to or less than 3.0 to 1.0, and (v) a total proved PV-10 value to total debt ratio of at least 1.50 to 1.00.

The credit agreement, as amended, contains customary events of default, including payment defaults, covenant defaults, certain events of bankruptcy and insolvency, defaults in the payment of other material debt, judgment defaults, breaches of representations and warranties, loss of material permits and licenses and a change in control. The credit agreement requires any wholly-owned subsidiaries to guarantee the obligations under the credit agreement.

On April 14, 2009, we and the administrative agent entered into the fourth amendment to the credit agreement which waived compliance with the current ratio financial covenant as of December 31, 2008 and March 31, 2009, and with the restrictive covenants related to accounts payable, permitted liens and permitted debt, subject to certain financial caps, until the next borrowing base redetermination expected in the fall of 2009. We believe that we may not be in compliance with certain restrictive covenants throughout 2009, but will seek additional waivers. There can be no assurance that we will be able to obtain such waivers or that such waivers will be obtained on acceptable terms. If we are unable to obtain future waivers and/or to comply with the restrictive covenants and are therefore in default, the lenders could avail themselves of the remedies under the credit agreement, including acceleration and foreclosure. Due to borrowing base limitations and waiver stipulations, we are unable to incur additional debt under the credit agreement.

After an event of default, the outstanding debt bears interest at the default rate under the terms of the credit agreement. The default rate is (i) with respect to principal, 2% over the otherwise applicable rate and (ii) with respect to interest, fees and other amounts, the Base Rate (as defined in the credit

facility), plus the Applicable Margin (as defined in the credit agreement), plus 2%. Any default interest is payable on demand. Failure to pay the default interest when the administrative agent demands would be another default. The lenders' remedies for defaults under the credit agreement are to terminate further borrowings, accelerate the repayment of indebtedness and/or ultimately foreclose on the collateral property.

Effective August 4, 2008, we and the administrative agent and lender entered into the second amendment to the credit agreement (the "second amendment"). The second amendment provided, among other things, for (i) an increase in the total quarterly senior debt to annualized EBITDA ratio from 2.0 to 1.0, to 3.0 to 1.0, (ii) an increase in interest at each utilization level for LIBOR borrowings, (iii) the amendment of the utilization calculation to be determined as the greater of (x) the percentage of credit exposure over the borrowing base or (y) the percentage of credit exposure over three times EBITDA minus permitted subordinated debt, and (iv) the payment of an amendment fee.

Effective September 30, 2008, we and the administrative agent and lender entered into the third amendment to the credit agreement (the "third amendment"). In addition to waiving compliance with the current ratio covenant as of September 30, 2008, the third amendment, among other things, required that immediately prior to any additional borrowings under the credit agreement, our ratio of current assets to current liabilities be not less than 1.00 to 1.00. As a result of this new condition to additional borrowings, we are currently unable to borrow additional amounts under the credit agreement. The third amendment also increased the interest rate payable under the credit agreement to either (i) the greater of the one month LIBOR plus 1.00% or a domestic bank rate, plus in either case an applicable margin of 0.75% to 1.75% based on utilization, or (ii) a sliding scale from the one, two, three or six month LIBOR, plus an applicable margin of 2.00% to 3.00% based on utilization, and provided for the payment of an amendment fee.

We and the administrative agent entered into the fourth amendment to the credit agreement (the "fourth amendment") dated as of April 14, 2009. In addition to waiving compliance with certain restrictive covenants, the fourth amendment reduced our borrowing base as described above.

Office Building Loan. On November 15, 2005, we entered into a mortgage loan secured by our office building in Sheridan, Wyoming in the aggregate principal amount of \$829,000. The promissory note provides for monthly payments of principal and interest in the initial amount of \$6,400, and unpaid principal bore interest at 6.875% until November 15, 2008, and at a variable base rate plus 0.5% thereafter and at 18% upon a default. The variable base rate is based on the lender's base rate. The maturity date of this mortgage is November 15, 2015, at which time a principal and interest payment of \$531,300 will become due. As of December 31, 2008, we had \$763,000 outstanding in principal on this mortgage. On November 15, 2008, the interest rate on our mortgage loan changed from a fixed rate of 6.875% to a variable rate. As of December 31, 2008, the variable rate was 4.75%.

Capital Expenditure Budget. We had a total capital expenditure budget of \$30.1 million for 2008 and expected to drill 146 gross (110 net) wells during that period. However, due to low CIG index prices, the economic climate and limited capital resources, we reduced our 2008 capital expenditure budget resulting in actual 2008 capital expenditures of \$27.8 million. In connection with our reduced capital expenditure budget, we also reduced our drilling and completion targets for 2008 to 117 gross (82 net) wells. We curtailed substantially all new drilling in the third and fourth quarters of 2008, and have shut-in a number of wells that are not economic at current natural gas price levels. If natural gas prices remain low, we expect to continue to operate with a reduced capital expenditure plan through 2009. Under our reduced capital expenditure plan, we would generally make such expenditures only as necessary to secure drilling permits in strategic areas, drill wells that secure leasehold positions and construct the necessary infrastructure to complete and hook-up wells that have already been drilled.

The CIG index price has been extremely volatile during 2007 and 2008 and at times reached unusually low levels. For instance, the CIG monthly index price per Mcf was \$1.78, \$3.41, \$2.78 and

\$4.63 for delivery in September, October, November and December of 2008, respectively. If prices remain low, our cash flows from operations will decrease and the borrowing base and borrowing availability under our credit facility could be further reduced. If we do not have sufficient cash flows and cannot obtain capital through our credit facility or otherwise, our ability to execute our development and acquisition plans, replace our reserves and maintain production levels could be greatly limited. If natural gas prices do not improve, we will consider alternatives to increase liquidity, including asset sales and issuances of equity. Our capital expenditure budget for 2009 will be dependent upon CIG index prices, our operating cash flows and the availability of additional capital resources.

Cash Flow from Operating Activities

Net cash provided by operating activities was approximately \$7.6 million for the year ended December 31, 2008, compared to net cash used by operating activities of \$16.7 million for the year ended December 31, 2007 and net cash provided by operating activities of \$6.0 million for the year ended December 31, 2006. The increase in 2008 was primarily due to an increase in our accounts payable balance, a decrease in our accounts receivables and prepaid expenses along with an impairment of our oil and gas properties.

As a result of low natural gas prices, our cash flows from operations have not been sufficient to fund our cash requirements and we have been required to draw on our credit facility. If natural gas prices continue to trend downward, our cash flows from operations will decrease and the borrowing base under our credit facility will be reduced.

Cash Flow from Investing Activities

Net cash used in investing activities was approximately \$26.9 million, \$9.4 million and \$63.9 million for the years ended December 31, 2008, 2007 and 2006, respectively. Net cash used in investing activities increased in 2008 by \$17.4 million from 2007 due to increased investment in the acquisition and development of undeveloped leaseholds along with the related infrastructure. Net cash used in investing activities decreased by approximately \$54.5 million in 2007 compared to 2006 due to decreased investment in the acquisition and development of undeveloped leaseholds primarily due to low gas prices in the Rocky Mountain region.

Cash Flow from Financing Activities

Net cash provided by financing activities was approximately \$11.5 million for the year ended December 31, 2008 as compared to \$29.5 million and \$59.9 million for the years ended December 31, 2007 and 2006, respectively. The change in 2007 from 2006 was primarily due to our April 2006 private placement and our May 2007 initial public offering. The change in 2008 from 2007 was primarily due to our borrowings of \$11.5 million under our credit facility in 2008 and net proceeds of approximately \$29.5 million from our May 2007 initial public offering.

In April 2006, we completed a private placement, exempt from registration under the Securities Act, of 12,835,230 shares of our common stock to qualified institutional buyers, non-U.S. persons and accredited investors at a price of \$11.00 per share, or \$10.23 per share net of the initial purchaser's discount and placement fee. Out of the approximately \$129.9 million of net proceeds (after expenses) we received in the private placement, we used (i) approximately \$53.6 million to redeem all of the outstanding shares of our Series A Redeemable Preferred Stock, including the payment of all accrued and unpaid dividends and a redemption premium, (ii) approximately \$27.0 million for our acquisition of the Green River Basin assets and (iii) approximately \$16.3 million to repurchase an aggregate of 1,593,783 shares of common stock at a price of \$10.23 per share from DLJ Merchant Banking and Gary W. Uhland, our former President, and (iv) approximately \$33.0 million to fund our development drilling program and pay additional offering expenses and for general corporate purposes.

In May 2007, we completed an initial public offering of 3,750,000 shares of our common stock at a price of \$9.00 per share, or \$8.37 per share net of underwriters' discounts and commissions. Out of the approximately \$30.3 million of net proceeds (after underwriters' discounts and commissions and offering expenses) we received in our initial public offering, we used \$7.0 million to pay down all of the outstanding indebtedness under our credit facility. We used the remainder of the net proceeds for capital expenditures, infrastructure development and general corporate purposes.

There have been no issuances of shares of common stock since our initial public offering except to employees, executive officers and directors pursuant to our incentive stock plan.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet financing arrangements or special purpose entities as of December 31, 2008. As such, we are not materially exposed to any financing, liquidity, market or credit risk that could arise if we had engaged in such financing arrangements.

Contractual Obligations

Please see Notes 8 and 9 of the notes to our audited financial statements appearing elsewhere in this report for information regarding our credit facility and other indebtedness.

The following table summarizes by period our contractual obligations as of December 31, 2008:

	<u>Total</u>	<u>2009</u>	<u>2010–2011</u>	<u>2012–2013</u>	<u>Thereafter</u>
	(In thousands)				
Notes payable in connection with the mortgage	\$ 763	\$ 30	\$ 64	\$ 73	\$ 596
Asset retirement obligations	3,366	341	835	633	1,557
Non-current production and property taxes	1,156	—	1,156	—	—
Total	<u>\$5,285</u>	<u>\$371</u>	<u>\$2,055</u>	<u>\$706</u>	<u>\$2,153</u>

At December 31, 2008, the commodity derivatives asset was valued at \$4,345,000, which represents a current receivable attributable to 2008.

ITEM 7A *QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK*

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risk. The term “market risk” refers to the risk of loss arising from adverse changes in natural gas prices or interest rates. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposure. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our natural gas production. The prices we receive for our production depend on many factors beyond our control. We seek to reduce our exposure to unfavorable changes in natural gas prices, which are subject to significant and often volatile fluctuation, through the use of fixed-price contracts. Our fixed-price contracts are comprised of energy swaps and collars. Fixed price contracts allow us to predict with greater certainty the effective natural gas prices to be received for hedged production and benefit operating cash flows and earnings when market prices are less than the fixed prices provided by the contracts. However, we will not benefit from market prices that are higher than the fixed prices in the contracts for hedged production. Collar structures provide for participation in price increases and decreases to the extent of the ceiling prices and floors provided in those contracts. With regard to hedging arrangements, our credit facility provides that acceptable commodity hedging arrangements cannot cover greater than 80 to 85%, depending on the measurement date, of our monthly production from our hydrocarbon properties that are used in the borrowing base determination, and that the fixed or floor price of our hedging arrangements must be equal to or greater than the gas price used by the lenders in determining the borrowing base.

The following table summarizes the estimated volumes, fixed prices, fixed price sales and fair value attributable to the fixed price contracts as of December 31, 2008. At December 31, 2008, we had hedged volumes through December 2009. Please see Note 6 and Note 20 of the notes to the audited financial statements appearing elsewhere in this report for further information regarding our derivatives.

	Year Ending December 31, 2009
	(Unaudited)
Natural Gas Collars:	
Contract volumes (MMBtu):	
Floor	730,000
Ceiling	730,000
Weighted-average fixed price per MMBtu(1):	
Floor	\$ 6.50
Ceiling	\$ 7.50
Fixed-price sales(2)	\$ 7.50
Fair value, net (thousands)(3)	\$ 1,707
Contract volumes (MMBtu)	912,500
Natural Gas Swaps:	
Contract volumes (MMBtu)	912,500
Weighted-average fixed price per MMBtu(1)	\$ 7.17
Fair value, net (thousands)(3)	\$ 2,638
Total Natural Gas Contracts:	
Contract volumes (MMBtu)	1,642,500
Fixed-price sales(2)	\$ 7.32
Fair value, net (thousands)(3)	\$ 4,345

- (1) Volumes hedged using the CIG index price published in the first issue of Inside FERC's Gas Market Report for each calendar month of the derivative transaction.
- (2) Assumes ceiling prices for natural gas collar volumes.
- (3) Fair value based on CIG index price in effect for each month as of December 31, 2008.

Interest Rate Risk

Borrowings under our credit facility bear interest at fluctuating market-based rates. Accordingly, our interest expenses are sensitive to market changes, which expose us to interest rate risk on current and future borrowings under our credit facility.

As of December 31, 2008 and March 31, 2009, we had \$11.5 million and \$10.5 million, respectively, in outstanding indebtedness under our credit facility. Borrowings under the credit facility bear interest either: (i) at the greater of the one month LIBOR plus 1.00% or a domestic bank rate, plus in either case an applicable margin of 0.75% to 1.75% based on utilization, or (ii) on a sliding scale from one, two, three, or six month LIBOR, plus an applicable margin of 2.00% to 3.00% based on utilization. The weighted average interest rate for borrowings under our credit facility was 5.3% for the year ended December 31, 2008. In light of the current economic climate, we expect that interest rates on alternative financing options to range from 8% to 12%. The availability of alternative financing arrangements and the interest rates thereof would depend on the type of financing and our ability to restructure our current indebtedness outstanding under our credit facility. Due to covenant restrictions in our credit facility, we are currently unable to borrow additional amounts.

A hypothetical increase of 1% in either the domestic bank rate or the LIBOR interest rates would increase gross interest expense approximately \$115,000 per year based on our outstanding indebtedness at December 31, 2008.

ITEM 8 FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Pinnacle Gas Resources, Inc.
Sheridan, Wyoming

We have audited the accompanying balance sheets of Pinnacle Gas Resources, Inc. (the “Company”) as of December 31, 2008 and 2007, and the related statements of operations, redeemable preferred stock and stockholders’ equity and cash flows for each of the years in the three year period ended December 31, 2008. 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 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, the financial statements referred to above present fairly, in all material respects, the financial position of Pinnacle Gas Resources, Inc. as of December 31, 2008 and 2007 and the results of their operations and their cash flows for each of the years in the three year period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America.

/s/ Ehrhardt Keefe Steiner & Hottman PC

Denver, Colorado
April 14, 2009

PINNACLE GAS RESOURCES, INC.

Balance Sheets

	<u>December 31, 2008</u>	<u>December 31, 2007</u>
	<u>(In thousands, except share and per share data)</u>	
ASSETS		
Current assets		
Cash and cash equivalents	\$ 346	\$ 8,151
Receivables		
Accrued gas sales	2,091	3,062
Joint interest receivables, net of \$100 allowance for doubtful accounts	4,824	6,040
Derivative instruments	4,345	556
Inventory of material held for exploration and development	83	174
Prepaid expenses	196	1,322
Total current assets	<u>11,885</u>	<u>19,305</u>
Property and equipment, at cost, net of accumulated depreciation	1,798	2,226
Oil and gas properties, using full cost accounting, net of accumulated depletion and impairment		
Proved	34,522	33,965
Unproved	86,827	88,820
Inventory of material held for exploration and development	384	505
Deposits	199	20
Restricted certificates of deposit	2,725	1,752
Total assets	<u>\$138,340</u>	<u>\$146,593</u>
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Long term debt-current portion	11,530	23
Trade accounts payable	10,112	7,767
Revenue distribution payable	4,625	6,534
Drilling prepayments from joint interest owners	28	28
Asset retirement obligations, current	341	363
Accrued liabilities	1,539	2,241
Total current liabilities	<u>28,147</u>	<u>16,956</u>
Asset retirement obligations, non-current	3,025	2,404
Production taxes, non-current	1,156	633
Long term debt-net of current portion	733	763
Total liabilities	<u>33,061</u>	<u>20,756</u>
Commitments and contingencies		
Series A Redeemable Preferred stock, \$0.01 par value; 25,000,000 authorized, 0 shares issued and outstanding at December 31, 2008 and 2007, respectively	—	—
Stockholders' equity		
Common stock, \$0.01 par value; 100,000,000 authorized and 29,193,573 and 29,019,751 shares issued and outstanding at December 31, 2008 and 2007, respectively	289	289
Additional paid-in capital	150,879	149,701
Accumulated deficit	(45,889)	(24,153)
Total stockholders' equity	<u>105,279</u>	<u>125,837</u>
Total liabilities and stockholders' equity	<u>\$138,340</u>	<u>\$146,593</u>

See Notes to Financial Statements

PINNACLE GAS RESOURCES, INC.

Statements of Operations

	For the Years Ended December 31,		
	2008	2007	2006
	(In thousands, except share and per share data)		
Revenues			
Gas sales	\$ 22,441	\$ 13,141	\$ 12,196
Earn-in joint venture	—	—	379
Total revenues	<u>22,441</u>	<u>13,141</u>	<u>12,575</u>
Cost of revenues and expenses			
Lease operating expenses	6,450	4,721	2,993
Production taxes	1,941	1,397	1,198
Marketing and transportation	4,694	3,464	1,962
General and administrative, net	6,674	5,179	4,343
Depreciation, depletion, amortization and accretion	9,322	6,516	6,673
Impairment of oil and gas properties	21,521	18,225	—
Total cost of revenues and expenses	<u>50,602</u>	<u>39,502</u>	<u>17,169</u>
Operating loss	(28,161)	(26,361)	(4,594)
Other income (expense)			
Gain on derivatives	5,762	2,211	7,362
Interest income	162	677	720
Other income	626	379	484
Unrealized derivative loss	—	—	(26)
Interest expense	(125)	(283)	(168)
Total other income	<u>6,425</u>	<u>2,984</u>	<u>8,372</u>
Net (loss)/income before income taxes	(21,736)	(23,377)	3,778
Income taxes	—	—	—
Net (loss)/income	(21,736)	(23,377)	3,778
Preferred dividends	—	—	(20,964)
Net loss attributable to common stockholders	<u>\$ (21,736)</u>	<u>\$ (23,377)</u>	<u>\$ (17,186)</u>
Basic and diluted net loss per share	\$ (0.75)	\$ (0.86)	\$ (0.87)
Weighted average shares outstanding—basic and diluted	29,096,411	27,281,680	19,783,118

See Notes to Financial Statements

PINNACLE GAS RESOURCES, INC.

Statements of Cash Flows
(In thousands)

	For the Years Ended December 31,		
	<u>2008</u>	<u>2007</u>	<u>2006</u>
Cash flows from operating activities			
Net (loss)/income	\$(21,736)	\$(23,377)	\$ 3,778
Adjustments to reconcile net (loss)/income to net cash (used in)/provided by operating activities			
Impairment of oil and gas properties	21,521	18,225	—
Depreciation, depletion, amortization and accretion	9,322	6,516	6,673
Gain on derivatives	(5,762)	(2,211)	(7,336)
Allowance for doubtful accounts	—	—	100
Stock-based compensation	1,184	867	368
Changes in assets and liabilities			
Decrease (increase) in receivables	2,187	2,499	(3,184)
Decrease in inventory of material for drilling and completion	91	97	209
Decrease (increase) in prepaid expenses	1,126	(928)	(281)
(Decrease) increase in accounts payable and accrued liabilities	1,634	(17,344)	6,179
Decrease in revenue distribution payable	(1,909)	(767)	(764)
(Decrease) increase in drilling prepayments	(28)	(261)	289
Asset retirement obligation settled this period	(48)	(1)	(2)
Net cash (used in)/provided by operating activities	<u>7,582</u>	<u>(16,685)</u>	<u>6,029</u>
Cash flows from investing activities			
Capital expenditures—exploration and production	(27,217)	(14,006)	(62,340)
Capital expenditures—property and equipment	(583)	(910)	(714)
Purchase of restricted certificates of deposits	(973)	43	(520)
Decrease (increase) in deposits	(179)	500	(1,657)
Decrease in inventory held for exploration and development	121	439	294
Realized gain on derivatives	1,973	4,511	663
Proceeds from the sale of assets held for sale	—	—	394
Net cash used in investing activities	<u>(26,858)</u>	<u>(9,423)</u>	<u>(63,880)</u>
Cash flows from financing activities			
Proceeds from the issuance of common stock	—	33,750	141,187
Issuance costs related to common stock	(6)	(4,232)	(11,252)
Dividends paid on preferred stock	—	—	(1,397)
Redemption of preferred stock including redemption premium	—	—	(52,174)
Repurchase and cancellation of common shares	—	—	(16,304)
Principal payments on note payable	(23)	(21)	(119)
Proceeds from the credit facility	11,500	—	—
Net cash provided by financing activities	<u>11,471</u>	<u>29,497</u>	<u>59,941</u>
Net increase (decrease) in cash and cash equivalents	<u>(7,805)</u>	<u>3,389</u>	<u>2,090</u>
Cash and cash equivalents at beginning of year	<u>8,151</u>	<u>4,762</u>	<u>2,672</u>
Cash and cash equivalents at end of year	<u>\$ 346</u>	<u>\$ 8,151</u>	<u>\$ 4,762</u>
Noncash investing and financing activities			
Capital expenditures included in trade accounts payable	\$ 7,732	\$ 7,200	\$ 6,232
Asset retirement obligation included in oil and gas properties	399	239	884
Dividend paid in kind with the issuance of additional preferred stock	—	—	1,207
Derivative liability related to preferred stock	—	—	232
Cashless exercise of warrants and options	—	—	15,428
Inventory used in oil and gas properties	—	—	(294)
Supplemental cash flow information			
Cash payments for interest, net of amount capitalized	\$ 125	\$ 115	\$ 168

See Notes to Financial Statements

Pinnacle Gas Resources, Inc.

Statements of Redeemable Preferred Stock and Stockholders' Equity

	Stockholders' Equity							
	Preferred Stock		Common Stock		Fair Value of Warrants and Options	Additional Paid-In Capital	Accumulated Deficit	Total
	Shares	Amount	Shares	Amount				
Balance at December 31, 2005	462,189	31,400	5,800,000	58	15,428	10,852	(4,554)	21,784
Dividends on preferred	—	—	—	—	—	(1,397)	—	(1,397)
Dividends paid in-kind on preferred . . .	12,132	1,207	—	—	—	—	—	—
Stock-based compensation	—	—	—	—	—	289	—	289
Issuance of restricted shares	—	—	27,270	—	—	79	—	79
Sales of common stock for cash in a private placement, net of offering costs of \$11,252	—	—	12,835,230	128	—	129,807	—	129,935
Redemption of preferred stock for cash, including redemption premium	(474,321)	(32,607)	—	—	—	(19,335)	—	(19,335)
Repurchase and cancellation of common stock	—	—	(1,593,783)	(16)	—	(16,288)	—	(16,304)
Cashless exercise of warrants and escalating options	—	—	8,062,584	81	(15,428)	15,347	—	—
Net income	—	—	—	—	—	—	3,778	3,778
Balance as of December 31, 2006	—	\$ —	25,131,301	\$251	\$ —	\$119,354	\$ (776)	\$118,829
Issuance of restricted shares	—	\$ —	155,500	\$ —	\$ —	\$ 158	\$ —	\$ 158
Forfeiture of restricted shares	—	—	(17,050)	—	—	—	—	—
Sale of common stock for cash, net of offering costs of \$4,232	—	—	3,750,000	38	—	29,480	—	29,518
Stock-based compensation	—	—	—	—	—	709	—	709
Net Loss	—	—	—	—	—	—	(23,377)	(23,377)
Balance at December 31, 2007	—	\$ —	29,019,751	\$289	—	\$149,701	\$(24,153)	\$125,837
Issuance of restricted shares	—	\$ —	244,650	\$ —	\$ —	\$ 571	\$ —	\$ 571
Forfeiture of restricted shares	—	—	(70,828)	—	—	—	—	—
Additional offering costs	—	—	—	—	—	(6)	—	(6)
Stock-based compensation	—	—	—	—	—	613	—	613
Net Loss	—	—	—	—	—	—	(21,736)	(21,736)
Balance at December 31, 2008	—	\$ —	29,193,573	\$289	—	\$150,879	\$(45,889)	\$105,279

See Notes to Financial Statements

PINNACLE GAS RESOURCES, INC.

Notes to Financial Statements

Note 1—Summary of Significant Accounting Policies

Business and Basis of Presentation

Pinnacle Gas Resources, Inc. is an independent energy company engaged in the acquisition, exploration and development of domestic onshore natural gas reserves. The Company primarily focuses its efforts on the development of coalbed methane, or CBM, properties located in the Rocky Mountain region, and it is a substantial holder of CBM acreage in the Powder River Basin. The Company has assembled a large, predominantly undeveloped CBM leasehold position, which it believes positions itself for significant long-term growth in production and proved reserves. In addition, the Company owns over 94% of the rights to develop conventional and unconventional oil and natural gas in zones below its existing CBM reserves. Substantially all of its undeveloped acreage as of December 31, 2008 was located in the northern end of the Powder River Basin in northeastern Wyoming and southern Montana.

As of December 31, 2008, the Company owned natural gas and oil leasehold interests in approximately 477,000 gross (332,000 net) acres, approximately 90% of which were undeveloped. At December 31, 2008, the Company had estimated net proved reserves of 27.7 Bcf, based on a year-end Colorado Interstate Gas, or CIG, index price of \$4.61 per Mcf. These net proved reserves were located on approximately 10% of its net acreage. Based on its drilling results to date, analysis of core samples and third-party results in adjacent areas, the Company believes that its remaining undeveloped CBM acreage has substantial commercial potential. None of its acreage or producing wells is associated with coal mining operations.

As of December 31, 2008, the Company owned interests in 663 gross (366 net) producing wells and operated 97% of these wells. During the year ended December 31, 2008, the Company drilled 117 gross (82 net) wells and produced an average of 10.6 MMcf per day net to its interest. The Company exited 2008 producing 10.1 MMcf per day net to its interest. During 2007, the Company drilled 87 gross (61 net) wells and produced an average of 9.3 MMcf per day net to its interest.

The Company had a total capital expenditure budget of \$30.1 million for 2008 and expected to drill 146 gross (110 net) wells during the period. However, due to low CIG index prices, the economic climate and limited capital resources, the Company reduced its 2008 capital expenditure budget resulting in actual 2008 capital expenditures of \$27.8 million. In connection with the reduced capital expenditure budget, the Company also reduced its drilling and completion targets for 2008. The Company curtailed substantially all new drilling in the fourth quarter of 2008, and shut-in a number of wells that are not economic at current natural gas price levels. If natural gas prices remain low, the Company expects to continue to operate with a reduced capital expenditure plan. Under its reduced capital expenditure plan, the Company expects to make such expenditures only as necessary to secure drilling permits in strategic areas, drill wells that secure leasehold positions and construct the necessary infrastructure to complete and hook-up wells that have already been drilled. The Company's capital expenditure budget for 2009 will be dependent upon CIG index prices, its cash flows and the availability of additional capital resources.

The Company's proportionate share of capital expenditures, production revenue and operating expenses from its oil and gas properties is included in the financial statements.

The Company is not in compliance with the current ratio financial covenant and certain other restrictive covenants related to accounts payable, permitted liens and permitted debt under the credit facility. On April 14, 2009, the Company entered into a fourth amendment to the credit facility that waived compliance with the current ratio covenant as of December 31, 2008 and March 31, 2009, and

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 1—Summary of Significant Accounting Policies (Continued)

with such other restrictive covenants, subject to certain financial caps, until the next borrowing base redetermination expected in the fall of 2009. In connection with the waiver of the restrictive covenants, the lenders reduced our borrowing base to \$9.0 million, with further monthly reductions until the borrowing base reaches \$6.5 million on October 1, 2009. The Company believes that it may not be in compliance with certain covenants throughout 2009, but management anticipates receiving waivers in the future based on prior dealings with the lender and compliance with the borrowing base limitations. Due to borrowing base limitations and waiver stipulations, the Company is currently not able to receive further credit extensions under the credit facility. Further, in accordance with Emerging Issues Task Force (“EITF”) Issue 86-30, the Company has classified the debt related to the credit facility of \$11.5 million in current liabilities as of December 31, 2008 because it is unlikely that the Company will have cured the noncompliance of the current ratio covenant during the next 12 months. However, such debt is due and payable to the administrative agent and lender in February 2011 pursuant the terms of the credit facility. The Company has remained in full compliance with the payment of principal and interest pertaining to the credit agreement including ensuring that the outstanding borrowings remain within the limitations of the borrowing base. The Company has further reduced the debt outstanding under the credit agreement to \$9.0 million as of April 14, 2009 which was in compliance with the new borrowing base requirements.

The Company is actively marketing certain assets to raise additional capital and is also reviewing alternatives for raising additional capital through equity and debt financing, capital restructuring and possible mergers. The Company sold its high pressure gas gathering system in the Cabin Creek project area in Wyoming, and its remaining interest in the Arvada project area in Wyoming in April 2009. The Company received approximately \$3.2 million in net proceeds from these sales, and used part of such proceeds to repay a portion of its indebtedness outstanding under the credit facility and plans to use the remainder for general operating purposes. The Company has also put additional hedges of its gas in place to secure certain operating cash flow levels during the remainder of 2009. From January through April 2009, the Company had 4,500 MMbtu per day hedged through a combination of a fixed price swap and a costless collar at a weighted average floor price of \$6.87 per MMbtu and a ceiling price of \$7.32 per MMbtu. From May through December 2009, the Company has 7,000 MMbtu per day hedged through a combination of a fixed price swap and a costless collar at a weighted average floor price of \$5.65 per MMbtu and a ceiling price of \$5.93 per MMbtu. The Company has also implemented various cost cutting measures, including reducing general and administrative costs through staff reductions, wage and benefit cuts and a hiring freeze. The Company has reduced lease operating expenses by renegotiating water disposal contracts, reducing service costs and temporarily shutting-in marginal wells. The Company continues to communicate with key vendors to manage its obligations and payables. Management believes that appropriate steps, including cost-cutting measures, are being taken to make operations sustainable in the future. Although the Company is pursuing various alternatives to provide additional liquidity, there is no assurance of the likelihood or timing of any of these transactions.

Use of Estimates

The preparation of the Company’s financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amount of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from these estimates. Significant estimates with

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 1—Summary of Significant Accounting Policies (Continued)

regard to the Company's financial statements include the estimated carrying value of unproved properties, the estimate of proved oil and gas reserve volumes and the related present value of estimated future net cash flows and the ceiling test applied to capitalized oil and gas properties, the estimate of the timing and cost of the Company's future drilling activity, the estimated cost and timing related to asset retirement obligations, the estimated fair value of derivative assets and liabilities, the realizability of deferred tax assets, the estimates of expenses and timing of the exercise of stock options, accrual of operating costs, capital expenditures and revenue, and estimates for litigation.

Cash and Cash Equivalents

Cash in excess of daily requirements is generally invested in money market accounts and commercial paper with maturities of three months or less. Such investments are deemed to be cash equivalents for purposes of the financial statements. The carrying amount of cash equivalents approximates fair value due to the short maturity and high credit quality of those investments. At times, the Company maintains deposits in financial institutions in excess of federally insured limits. Management monitors the soundness of the financial institutions and believes the Company's risk is negligible.

Accounts Receivable

The Company's revenue producing activities are conducted primarily in Wyoming. The Company grants credit to qualified customers, which potentially subjects the Company to credit risk resulting from, among other factors, adverse changes in the industry in which the Company operates and the financial condition of its customers. The Company continuously monitors collections and payments from its customers and if necessary, records an allowance for doubtful accounts based upon historical experience and any specific customer collection issues identified. As of December 31, 2008 and 2007, the Company had an allowance of \$100,000.

Inventory

Pinnacle acquires inventory of oil and gas equipment, primarily tubulars, to take advantage of quantity pricing and to secure a readily available supply. Inventory is valued at the lower of average cost or market. Inventory is used in the development of gas properties, and to the extent it is estimated that it will be billed to other working interest owners during the next year, it is included in current assets. Otherwise, inventory is recorded in other non-current assets.

Property and Equipment

Property and equipment is comprised primarily of a building, computer hardware and software, vehicles and equipment and is recorded at cost. Renewals and betterments that substantially extend the useful lives of the assets are capitalized. Maintenance and repairs are expensed when incurred. Depreciation and amortization is provided using the straight-line method over the estimated useful lives of the assets as follows:

Buildings	30 years
Computer hardware and software	3-5 years
Machinery, equipment and vehicles	5 years
Office furniture and equipment	3-5 years

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 1—Summary of Significant Accounting Policies (Continued)

Long-Lived Assets

Long-lived assets to be held and used in the Company's business are reviewed for impairment whenever events or changes in circumstances indicate that the related carrying amount may not be recoverable. When the carrying amounts of long-lived assets exceed the fair value, which is generally based on discounted expected future cash flows, the Company records an impairment. No impairments were recorded during the years ended December 31, 2008, 2007 and 2006.

Oil and Gas Properties

The Company utilizes the full cost method of accounting for oil and gas producing activities. Under this method, all costs associated with property acquisition, exploration and development, including costs of unsuccessful exploration, costs of surrendered and abandoned leaseholds, delay lease rentals and the fair value of estimated future costs of site restoration, dismantlement and abandonment activities are capitalized within a cost center. The Company's oil and gas properties are all located within the United States, which constitutes a single cost center. The Company capitalizes lease operating expenses associated with exploration and development of unevaluated oil and gas properties. No gain or loss is recognized upon the sale or abandonment of undeveloped or producing oil and gas properties unless the sale represents a significant portion of gas properties and the gain significantly alters the relationship between capitalized costs and proved gas reserves of the cost center. Expenditures for maintenance and repairs are charged to lease operating expense in the period incurred.

Depreciation, depletion and amortization of oil and gas properties ("DD&A") is computed on the unit-of-production method based on proved reserves. Amortizable costs include estimates of future development costs of proved undeveloped reserves and asset retirement obligations. The Company invests in unevaluated oil and gas properties for the purpose of exploration for proved reserves. The costs of such assets, including exploration costs on properties where a determination of whether proved oil and gas reserves will be established is still under evaluation, and any capitalized interest and lease operating expenses, are included in unproved oil and gas properties at the lower of cost or estimated fair market value and are not subject to amortization. On a quarterly basis, such costs are evaluated for inclusion in the costs to be amortized resulting from the determination of proved reserves, impairments, or reductions in value. To the extent that the evaluation indicates these properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. Abandonment of unproved properties are accounted for as an adjustment to capitalized costs related to proved oil and gas properties, with no losses recognized. The Company recorded an impairment of unproved properties of \$5.6, \$0.7 and \$0 million, respectively, during the years ended December 31, 2008, 2007 and 2006. (See Note 4 for additional discussion of unproved properties). Substantially all other unproved property costs are expected to be developed and included in the amortization base over the next three to five years. Salvage value is taken into account in determining depletion rates and is based on the Company's estimate of the value of equipment and supplies at the time the well is abandoned. The estimated salvage value of equipment used in determining the depletion rate was \$7.3, \$6.4 and \$5.7 million as of December 31, 2008, 2007, and 2006 respectively.

Under full cost method of accounting rules, capitalized costs less accumulated depletion and related deferred income taxes may not exceed a "ceiling" value which is the sum of (1) the present value discounted at 10% of estimated future net revenue using current prices and costs, including the effects of derivative instruments designated as cash flow hedges but excluding the future cash outflows

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 1—Summary of Significant Accounting Policies (Continued)

associated with settling asset retirement obligations that have been accrued on the balance sheet, less any related income tax effects; plus (2) the cost of properties not being amortized, if any; plus (3) the lower of costs or estimated fair value of unproved properties; less (4) the income tax effects related to differences in the book to tax basis of oil and gas properties. This is referred to as the “full cost ceiling limitation.” If capitalized costs exceed the limit, the excess must be charged to expense. The expense may not be reversed in future periods. At the end of each quarter, the Company calculates the full cost ceiling limitation. At December 31, 2008, the full cost ceiling limitation exceeded the capitalized costs of oil and gas properties by approximately \$21.5 million, based upon a natural gas price of \$4.61 per Mcf in effect at that date. As such, the Company was required to record an impairment in the fourth quarter of 2008. Based on the CIG index price of \$2.20 per Mcf on April 9, 2009, the Company would have been required to take a total impairment of approximately \$46.7 million at December 31, 2008. For the year ended December 31, 2007, the Company recorded an impairment of \$18.2 million resulting from low commodity prices throughout the year, specifically in the first, second and third quarters of 2007. A decline in gas prices or an increase in operating costs or reductions in economically recoverable reserve quantities could result in the recognition of additional impairments of the Company’s oil and gas properties in future periods.

Asset Retirement Obligations

Pinnacle follows the provisions of Statement of Financial Accounting Standards (“SFAS”) No. 143, “Accounting for Asset Retirement Obligations.” SFAS No. 143 generally applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. SFAS No. 143 requires the Company to recognize an estimated liability for costs associated with the abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation with a corresponding increase to the carrying value of the related long-lived asset is recorded at the time a well is completed or acquired. The increased carrying value is depleted using the units-of-production method, and the discounted liability is increased through accretion over the remaining life of the respective oil and gas properties.

The estimated liability is based on historical gas industry experience in abandoning wells, including estimated economic lives, external estimates as to the cost to abandon the wells in the future and federal and state regulatory requirements. The Company’s liability is discounted using its best estimate of its credit-adjusted risk free rate. The credit adjusted risk free rate is based on our borrowing under the credit facility or, if borrowings are not available under the credit facility, due to exhaustion of the borrowing base or covenant limitations, the rate is based on the interest rate available from our banks for senior secured debt or mezzanine debt. Based on our current inability to borrow against our facility, (see Note 8) our credit adjusted risk free rate at December 31, 2008 was the prime rate plus 7% or 10.25%. Revisions to the liability could occur due to changes in estimated abandonment costs, changes in well economic lives or if federal or state regulators enact new requirements regarding the abandonment of wells.

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 1—Summary of Significant Accounting Policies (Continued)

Changes in the carrying amount of the asset retirement obligations are as follows:

	December 31,	
	2008	2007
	(In thousands)	
Beginning balance of asset retirement obligations	\$2,767	\$2,321
Additional obligations added during the period	399	239
Obligations settled during the period	(48)	(1)
Revisions in estimates	—	—
Accretion expense	248	208
Ending balance of asset retirement obligations	\$3,366	\$2,767

Capitalized Interest

The Company capitalizes interest costs to unproved oil and gas properties on expenditures made in connection with exploration and development projects that are not subject to current depletion. Interest is capitalized only for the period that activities are in progress to bring these projects to their intended use. Interest costs capitalized in 2008, 2007 and 2006 were \$199,000, \$0 and \$0, respectively.

Restricted Assets

Certificates of deposit. The Company holds a certificate of deposit (“CD”), which expires in July 2009, totaling \$157,000. The CD is collateral on bonding required by the State of Wyoming, the State of Montana and the Federal Bureau of Land Management. Because the Company intends to renew the CD in order to maintain its bonding requirements, the Company has included the CD in other non-current assets as of December 31, 2008. Additionally, the Company holds two CDs for \$604,000 and \$964,000 which were issued in February 2006 and May 2008, respectively, and will expire in February 2010 and May 2009, respectively. These CD’s collateralize letters of credit in favor of Powder River Energy Corporation, a local rural electric association, in order to secure power lines to the Kirby and Deer Creek areas. The Company has included these amounts in non-current assets as of December 31, 2008 because the Company also intends to renew the CDs in order to maintain a power supply on a long-term basis. In April 2007, the Company issued a \$1,000,000 letter of credit which expires in April 2009 in favor of Bitter Creek Pipelines, LLC to secure the construction of a high pressure pipeline and related compression facilities to the Company’s Deer Creek and Kirby areas. The Company has included this amount in non-current assets as of December 31, 2008 because the pipeline and compression facilities are not expected to be completed and fully utilized until the end of 2010.

Deposits. The Company has included approximately \$199,000 and \$20,000 related to royalty payments in deposits in the accompanying balance sheet at December 31, 2008 and 2007, respectively.

Gas Sales

Pinnacle uses the sales method for recording natural gas sales. Sales of gas applicable to Pinnacle’s interest in producing natural gas leases are recorded as revenues when the gas is metered and title transferred pursuant to the gas sales contracts covering its interest in gas reserves. During such times as Pinnacle’s sales of gas exceed its pro rata ownership in a well, such sales are recorded as revenues unless total sales from the well have exceeded Pinnacle’s share of estimated total gas reserves

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 1—Summary of Significant Accounting Policies (Continued)

underlying the property at which time such excess is recorded as a gas imbalance liability. At December 31, 2008 and 2007, there was no such liability recorded.

General and Administrative Expenses

General and administrative expenses are reported net of amounts allocated and billed to working interest owners of gas properties operated by the Company.

Transportation Costs

The Company accounts for transportation costs under Emerging Issues Task Force Issues 00-10, “Accounting for Shipping and Handling Fees and Costs,” whereby amounts paid for transportation are classified as operating expenses.

Per Share Information

Basic earnings (loss) per share is computed by dividing net income (loss) from continuing operations attributable to common stock by the weighted average number of shares of common stock outstanding during each period. Diluted earnings per share is computed by adjusting the average number of shares of common stock outstanding for the dilutive effect, if any, of common stock equivalents such as stock options and warrants. Diluted net loss per share was the same as basic loss per share for the years ended December 31, 2008, 2007 and 2006 because potential common stock equivalents were anti-dilutive.

Certain options to purchase shares of Pinnacle’s common stock were excluded from the dilution calculations because the shares were antidilutive. During the years ended December 31, 2008, 2007 and 2006, shares that were excluded from the calculation because they were antidilutive were 676,250, 871,000 and 1,035,000, respectively.

Income Taxes

The Company uses the asset and liability method of accounting for income taxes, in accordance with SFAS No. 109, “Accounting for Income Taxes.” Deferred tax assets and liabilities are recognized for the expected future tax consequences of temporary differences between the financial statement and tax bases of assets and liabilities. If appropriate, deferred tax assets are reduced by a valuation allowance which reflects expectations of the extent to which such assets will be realized. As of December 31, 2008, 2007 and 2006, the Company had recorded a full valuation allowance for its net deferred tax asset.

Derivatives

The Company accounts for derivative instruments or hedging activities under the provisions of SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities.” SFAS No. 133 requires the Company to record derivative instruments at their fair value. If the derivative is designated as a fair value hedge, the changes in the fair value of the derivative and of the hedged item attributable to the hedged risk are recognized in earnings. If the derivative is designated as a cash flow hedge, the effective portions of changes in the fair value of the derivative are recorded in other comprehensive income (loss) and are recognized in the statement of operations when the hedged item affects earnings. Ineffective portions of changes in the fair value of cash flow hedges, if any, are recognized in earnings. Changes in the fair value of derivatives that do not qualify for hedge treatment are recognized in earnings.

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 1—Summary of Significant Accounting Policies (Continued)

The Company periodically hedges a portion of its oil and gas production through swap and collar agreements. The purpose of the hedges is to provide a measure of stability to the Company's cash flows in an environment of volatile oil and gas prices and to manage the exposure to commodity price risk. Management of the Company decided not to use hedge accounting for these agreements. Therefore, in accordance with the provisions of SFAS No. 133, the changes in fair market value are recognized in earnings. See Note 6 for additional discussion of derivatives.

Stock-Based Compensation

Effective January 1, 2006, the Company adopted SFAS No. 123(R), "Share-Based Payments," which requires companies to recognize compensation expense for share-based payments based on the estimated fair value of the awards.

Under SFAS No. 123(R), compensation expense for all share-based payments granted subsequent to January 1, 2006, based on the estimated grant date fair value, has been recorded for the years ended December 31, 2008, 2007 and 2006. The Company records compensation expense related to non-employees under the provisions of SFAS No. 123 and Emerging Issues Task Force EITF 96-18 "Accounting for Equity Instruments that are Issued to Other than Employees for Acquiring, or in conjunction with Selling Goods or Services" and recognizes compensation expense over the vesting periods of such awards.

The Company has computed the fair value of options granted using the Black-Scholes option pricing model. In order to calculate the fair value of the options, certain assumptions are made regarding components of the model, including risk-free interest rate, volatility, expected dividend yield, and expected option life. Changes to the assumptions could cause significant adjustments to valuation. The Company estimated the volatility rate of its common stock at the date of the grant based on the historical volatility of comparable companies. The Company factored in expected retention rates combined with vesting periods to determine the average expected life. The risk-free interest rate is based on the U.S. Treasury yield curve in effect at the time of the grant. No options were granted during the year ended December 31, 2008. Accordingly, the Company has computed the fair value of all options granted during the years ended December 31, 2008, 2007 and 2006 using the Black-Scholes option pricing model and the following weighted average assumptions:

	Year Ended December 31,		
	2008	2007	2006
Expected Volatility	N/A	35%	35%
Dividend Yield	N/A	—	—
Risk Free Interest Rate	N/A	4.79% to 4.80%	4.30% to 5.03%
Weighted Average expected life (in years)	—	5	5

New Accounting Pronouncements

Effective January 1, 2008, the Company adopted the fair value measurement and disclosure provisions of Statement of Financial Accounting Standards (SFAS) No. 157, *Fair Value Measurements* (SFAS 157), which establishes specific criteria for the fair value measurements of financial and nonfinancial assets and liabilities that are already subject to fair value measurements under current

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 1—Summary of Significant Accounting Policies (Continued)

accounting rules. SFAS 157 also requires expanded disclosures related to fair value measurements. In February 2008, the FASB approved FASB Staff Position (FSP) SFAS No. 157-2, *Effective Date of FASB Statement No. 157*, which allows companies to elect a one-year delay in applying SFAS 157 to certain fair value measurements, primarily related to nonfinancial instruments. The Company elected the delayed adoption date for the portions of SFAS 157 impacted by FSP SFAS 157-2. The partial adoption of SFAS 157 was prospective and did not have a significant effect on the Company's financial statements. The Company does not expect that the application of the deferred portion of SFAS 157 to the nonrecurring fair value measurements of its nonfinancial assets and liabilities will have a material impact on the Company's financial statements. In accordance with FSP SFAS 157-2, the fair value measurements for nonfinancial assets and liabilities will be adopted effective for fiscal years beginning after November 15, 2008.

In October 2008, the FASB issued FSP SFAS No. 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active*. FSP SFAS 157-3 clarifies the application of SFAS 157, which the Company adopted as of January 1, 2008, in situations where the market is not active. The Company has considered the guidance provided by FSP SFAS 157-3 in its determination of estimated fair values as of December 31, 2008.

Also effective January 1, 2008, the Company adopted SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities—Including an amendment of FASB Statement No. 115* (SFAS 159). SFAS 159 creates a "fair value option" under which an entity may elect to record certain financial assets or liabilities at fair value upon their initial recognition. Subsequent changes in fair value would be recognized in earnings as those changes occur. The election of the fair value option would be made on a contract-by-contract basis and would need to be supported by concurrent documentation or a preexisting documented policy. SFAS 159 requires an entity to separately disclose the fair value of these items on the balance sheet or in the footnotes to the financial statements and to provide information that would allow the financial statement user to understand the impact on earnings from changes in the fair value. The Company did not elect the fair value option for any of their financial assets or liabilities.

In December 2007, the FASB issued SFAS No. 141(R), "Business Combinations," which requires the acquiring entity in a business combination to recognize and measure all assets and liabilities assumed in the transaction and any non-controlling interest in the acquiree at fair value as of the acquisition date. SFAS No. 141 (R) also establishes guidance for the measurement of the acquirer shares issued in consideration for a business combination, the recognition of contingent consideration, the accounting treatment pre-acquisition gain and loss contingencies, the treatment of acquisition related transaction costs, and the recognition of changes in the acquirer's income tax valuation allowance and deferred taxes. SFAS No. 141(R) is effective for fiscal years beginning after December 15, 2008 and is to be applied prospectively as of the beginning of the fiscal year in which the statement is applied. Early adoption is not permitted. SFAS No. 141(R) will be effective for the Company beginning with the 2009 fiscal year. The impact of the adoption of SFAS No. 141(R) on the Company's financial statements will largely be dependent on the size and nature of the business combinations completed after the adoption of this statement.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities*. SFAS No. 161 is intended to improve financial reporting by requiring transparency about the location and amounts of derivative instruments in an entity's financial statements, how

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 1—Summary of Significant Accounting Policies (Continued)

derivative instruments and related hedged items are accounted for under FAS No. 133, and how derivative instruments and related hedged items affect its financial position, financial performance and cash flows. SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. The adoption of this pronouncement will not have an impact on the Company's financial statements, but it will require the Company to expand its disclosures about derivative instruments.

On December 31, 2008, the Securities and Exchange Commission ("SEC") published the 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 SEC will require companies to comply with the amended disclosure requirements for registration statements filed after January 1, 2010, and for annual reports for fiscal years ending on or after December 15, 2009. Early adoption is not permitted. The Company is currently assessing the impact that the adoption will have on the Company's disclosures, operating results, financial position, and cash flows.

Note 2—Property and Equipment

Property and equipment consists of the following:

	December 31,	
	2008	2007
	(In thousands)	
Building	\$ 1,420	\$ 1,420
Computer hardware and software	1,013	964
Machinery, equipment and vehicles	1,686	1,192
Office furniture and equipment	212	201
	<u>4,331</u>	<u>3,777</u>
Less accumulated depreciation and amortization	<u>(2,533)</u>	<u>(1,551)</u>
Total	<u>\$ 1,798</u>	<u>\$ 2,226</u>

Depreciation and amortization expense related to property and equipment for the years ended December 31, 2008, 2007, and 2006, was \$1,012,000, \$792,000, and \$496,000 respectively.

Note 3—Acquisitions and Divestitures

2006 Transactions

On April 20, 2006, the Company purchased undeveloped natural gas properties, including related interests and assets, located in the Green River Basin of Wyoming from Kennedy Oil for an aggregate purchase price of approximately \$27.0 million in cash. The undeveloped leasehold is located in Sweetwater County in the Hay Reservoir area of the Green River Basin. In addition, the Company

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 3—Acquisitions and Divestitures (Continued)

acquired a 65% working interest in existing deep rights below the base of the Fort Union formation. The acquisition was funded with a portion of the net proceeds from the April 2006 private placement.

Effective June 1, 2006, Pinnacle acquired a 100% working interest in 10 producing wells and 1,410 gross acres in the Recluse area for a total purchase price of \$1,575,000.

2007 Transactions

There were no significant acquisitions or divestitures of property in 2007.

2008 Transactions

There were no significant acquisitions or divestitures of property in 2008.

Note 4—Unproved Properties

The Company is currently participating in coalbed methane gas exploration and development activities on acreage in Montana and Wyoming. At December 31, 2008, a determination cannot be made about the extent of additional gas reserves that should be classified as proved reserves as a result of the exploration activities to date. Consequently, the associated property costs and exploration costs have been excluded in computing DD&A for the full cost pool. The Company will begin to calculate DD&A on these costs when the project is evaluated, which is currently estimated to be over the next one to five years. These costs are evaluated for inclusion in the costs to be amortized resulting from the determination of proved reserves, impairments or reductions in value. To the extent that the evaluation indicates these properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. For the year ending December 31, 2008 impairments of \$1.6 million and \$4.0 million were incurred in the third and fourth quarter, respectively.

Costs excluded from amortization relating to unproved properties at December 31, 2008 are as follows (in thousands):

<u>Period Incurred</u>	<u>Acquisition Costs</u>	<u>Exploration Costs</u>	<u>Development Costs</u>	<u>Capitalized Interest</u>	<u>Total</u>
2003	\$12,915	\$ —	\$—	\$ —	\$12,915
2004	112	—	—	—	112
2005	13,167	1,418	—	148	14,733
2006	30,316	27,018	—	—	57,334
2007(1)	1,147	2,579	—	—	3,726
2008(1)	(3,378)	1,186	—	199	(1,993)
	<u>\$54,279</u>	<u>\$32,201</u>	<u>\$—</u>	<u>\$347</u>	<u>\$86,827</u>

(1) Acquisition costs included \$5.6 million and \$0.7 million of impairments for the years ended December 31, 2008 and 2007, respectively.

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 4—Unproved Properties (Continued)

Suspended Wells Costs

The following table reflects the net changes in capitalized exploratory well costs during 2008, 2007 and 2006, and does not include amounts that were capitalized and either subsequently expensed or reclassified to producing well costs in the same period.

	For the Years Ended December 31,		
	2008	2007	2006
	(In thousands)		
Beginning balance	\$31,015	\$28,436	\$ 4,938
Additions to capitalized exploratory well costs pending determination of proved reserves	5,551	6,659	27,018
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves	(4,365)	(4,080)	(3,520)
Ending balance	\$32,201	\$31,015	\$28,436

The following table provides an aging of capitalized exploratory well costs based on the date the drilling was completed and the number of projects for which exploratory well costs have been capitalized since the completion of drilling:

	For the Years Ended December 31,		
	2008	2007	2006
	(In thousands)		
Exploratory well costs capitalized for one year or less	\$ 5,551	\$ 6,659	\$27,018
Exploratory well costs capitalized for more than one year	26,650	24,356	1,418
Ending balance at December 31,	\$32,201	\$31,015	\$28,436
Number of projects with exploratory well costs that have been capitalized more than a year	3	3	1

The \$26.7 million of exploratory well costs capitalized for more than one year are for wells located in Kirby and Cabin Creek. These wells are hooked up to gas sales pipelines and are in the dewatering phase. As soon as the Company receives this approval, the wells will begin the dewatering phase. In the Kirby project area of Montana, the Sweetwater project area of Wyoming and the Cabin Creek area of Wyoming, as the wells produce gas and are determined to be proved reserves, the well costs will be reclassified to the full cost pool.

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 5—Accrued Liabilities

Accrued liabilities consist of the following:

	December 31,	
	2008	2007
	(In thousands)	
Production taxes	\$ 2,573	\$2,333
Payroll and related taxes	122	541
	2,695	2,874
Less production taxes due after one year	(1,156)	(633)
Total	\$ 1,539	\$2,241

Accrued liabilities consist of production taxes and payroll expenses that are attributable to the fiscal year end but are not payable until after fiscal year end.

Note 6—Derivatives

Hedging Contracts

As of December 31, 2008, 2007 and 2006, the Company had natural gas hedges in place as follows:

Product	MMbtu per Day	Fixed Price Range	Time Period
<i>December 31, 2008</i>			
Natural Gas—Collar	2,000	\$6.50–\$7.50	1/09–12/09
Natural Gas—Swap	2,500	\$7.17–\$7.17	1/09–12/09
<i>December 31, 2007</i>			
Natural Gas—Collar	3,000	\$6.50–\$8.20	1/08–12/08
<i>December 31, 2006</i>			
Natural Gas—Collar	1,000	\$5.00–\$5.20	10/04–9/07
Natural Gas—Collar	1,000	\$6.50–\$10.50	9/06–12/07
Natural Gas—Collar	3,000	\$7.00–\$9.05	1/07–12/07

The Company has elected not to designate these derivatives as cash flow hedges under provisions of SFAS No. 133. These derivative instruments are marked to market at the end of each reporting period and changes in the fair value are recorded in the accompanying statements of operations. The aggregate fair values of these contracts were estimated to be assets totaling \$4,345,000 and \$556,000 at December 31, 2008 and 2007, respectively. The Company realized hedging gains in 2008, 2007 and 2006 of \$1,973,000, \$4,511,000, and \$663,000 respectively which amounts are included in gains/losses on derivatives in the statement of operations and are included in the cash flows used in investing activities in the statements of cash flows. As a result of the change in the fair value of the commodity derivatives, the Company had an unrealized gain of \$3,789,000 for the year ended December 31, 2008, an unrealized loss of \$2,300,000 for the year ended December 31, 2007, and an unrealized gain of \$6,699,000 for the year ended December 31, 2006. Unrealized and realized gains and losses are included in gains or losses on derivatives in the statement of operations.

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 6—Derivatives (Continued)

The Company is exposed to credit risk to the extent of nonperformance by the counterparties in the derivative contracts discussed above; however, the Company does not anticipate such nonperformance.

Note 7—Revenue Distributions Payable

Revenue distributions payable consist of the following:

	December 31,	
	2008	2007
	(In thousands)	
Revenue payable on current production	\$ 924	\$ 844
Revenues payable in suspense	3,701	5,690
Total revenues payable	\$4,625	\$6,534

The Company operates and disburses revenue to other working interest owners and royalty owners. Proceeds from gas sales are distributed and paid around 45 days after the end of the respective sales month. Revenue held in suspense is due primarily to the issuance of title opinions for wells in which the Company holds funds to distribute. Once a title opinion is received, revenue held in suspense is placed in line for payment under the normal payment cycle indicated above.

Note 8—Line-of-Credit

Effective February 12, 2007, the Company entered into a credit facility which permits borrowings up to the borrowing base as designated by the administrative agent. As of December 31, 2008 and March 31, 2009, the Company had \$11.5 million and \$10.5 million, respectively, of debt outstanding under the facility. As described below, the Company is currently unable to borrow additional amounts under the credit facility due to covenant limitations and may be further limited in the future based on borrowing base limitations.

As of December 31, 2008, the borrowing base under the credit facility was approximately \$13.2 million. The borrowing base was subject to automatic reductions of approximately \$666,667 per month until it reached \$10.5 million on April 1, 2009. As of April 13, 2009, the Company's borrowing base was reduced to \$9.0 million, subject to automatic reductions of \$500,000 per month until it reaches \$6.5 million on October 1, 2009 where it will remain until the next borrowing base redetermination. If natural gas prices do not improve, the Company expects that its borrowing base could be further reduced in the future.

The borrowing base is determined on a semi-annual basis and at such other additional times, up to twice yearly, as may be requested by either us or the administrative agent and is determined by the administrative agent in accordance with customary practices and standards for loans of a similar nature, although such determination is at the administrative agent's discretion as the credit agreement does not provide a specific borrowing base formula.

Borrowings under this credit facility may be used solely to acquire, explore or develop oil and gas properties and for general corporate purposes. The credit facility matures February 12, 2011.

The obligations under the credit facility are secured by liens on (i) no less than 90% of the net present value of the oil and gas to be produced from our oil and gas properties that are included in the

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 8—Line-of-Credit (Continued)

borrowing base determination, calculated using a discount rate of 10% per annum and reserve estimates, prices and production rates and costs, (ii) options to lease, seismic options, permits, and records related to such properties, and (iii) seismic data.

Borrowings under our credit facility, as amended, bear interest either: (i) at the greater of the one month London interbank offered rate, or LIBOR, plus 1.00% or a domestic bank rate, plus in either case an applicable margin of 0.75% to 1.75% based on utilization, or (ii) on a sliding scale from the one, two, three or six month LIBOR, plus an applicable margin of 2.00% to 3.00% based on utilization. The credit agreement provides for various fees, including a quarterly commitment fee of 0.5% per annum and engineering fees to the administrative agent in connection with a borrowing base determination. In addition, the credit facility provided for an up front fee of \$27,000, which was paid on the closing date of the credit facility, and an additional arrangement fee of 1% based on utilization. Borrowings under this credit facility may be prepaid without premium or penalty, except on Eurodollar advances.

The credit agreement, as amended, contains covenants that among other things restrict the Company's ability (subject to certain exceptions) to do the following:

- incur liens;
- incur debt;
- make investments in other persons;
- declare dividends or redeem or repurchase stock;
- engage in mergers, acquisitions, consolidations and asset sales or amend our organizational documents;
- enter into certain hedging arrangements;
- amend material contracts; and
- enter into related party transactions.

With regard to hedging arrangements, the credit facility provides that acceptable commodity hedging arrangements cannot cover greater than 80 to 85%, depending on the measurement date, of our monthly production from our hydrocarbon properties that are used in the borrowing base determination, and that the fixed or floor price of our hedging arrangements must be equal to or greater than the gas price used by the lenders in determining the borrowing base.

The credit agreement, as amended, also requires that that the Company satisfy certain affirmative covenants, meet certain financial tests, maintain certain financial ratios and make certain customary indemnifications to lenders and the administrative agent. The financial covenants include requirements to maintain: (i) a ratio of EBITDA to cash interest expense of not less than 3.00 to 1.00, (ii) a ratio of current assets to current liabilities of not less than 1.00 to 1.00, (iii) a total debt to annualized EBITDA ratio of not more than 3.0 to 1.0, (iv) a quarterly total senior debt to annualized EBITDA ratio equal to or less than 3.0 to 1.0, and (v) a total proved PV-10 value to total debt ratio of at least 1.50 to 1.00.

The credit agreement, as amended, contains customary events of default, including payment defaults, covenant defaults, certain events of bankruptcy and insolvency, defaults in the payment of other material debt, judgment defaults, breaches of representations and warranties, loss of material

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 8—Line-of-Credit (Continued)

permits and licenses and a change in control. The credit agreement requires any wholly-owned subsidiaries to guarantee the obligations under the credit agreement.

On April 14, 2009, we and the administrative agent entered into the fourth amendment to the credit agreement which waived compliance with the current ratio financial covenant as of December 31, 2008 and March 31, 2009 and with the restrictive covenants related to accounts payable, permitted liens and permitted debt until the next borrowing base redetermination, subject to certain financial caps. The Company believes that it may not be in compliance with certain restrictive covenants throughout 2009, but will seek additional waivers. There can be no assurance that the Company will be able to obtain such waivers or that such waivers will be obtained on acceptable terms. If the Company is unable to obtain future waivers and/or comply with the restrictive covenants and are therefore in default, the lenders could avail themselves of the remedies under the credit agreement, including acceleration and foreclosure.

After an event of default, the outstanding debt bears interest at the default rate under the terms of the credit agreement. The default rate is (i) with respect to principal, 2% over the otherwise applicable rate and (ii) with respect to interest, fees and other amounts, the Base Rate (as defined in the credit facility), plus the Applicable Margin (as defined in the credit agreement), plus 2%. Any default interest is payable on demand. Failure to pay the default interest when the administrative agent demands would be another default. The lenders' remedies for defaults under the credit agreement are to terminate further borrowings, accelerate the repayment of indebtedness and/or ultimately foreclose on the collateral property.

Effective August 4, 2008, the Company and the administrative agent and lender entered into the second amendment to the credit agreement (the "second amendment"). The second amendment provided, among other things, for (i) an increase in the total quarterly senior debt to annualized EBITDA ratio from 2.0 to 1.0, to 3.0 to 1.0, (ii) an increase in interest at each utilization level for LIBOR borrowings, (iii) the amendment of the utilization calculation to be determined as the greater of (x) the percentage of credit exposure over the borrowing base or (y) the percentage of credit exposure over three times EBITDA minus permitted subordinated debt, and (iv) the payment of an amendment fee.

Effective September 30, 2008, the Company and the administrative agent and lender entered into the third amendment to the credit agreement (the "third amendment"). In addition to waiving compliance with the current ratio covenant as of September 30, 2008, the third amendment, among other things, requires that immediately prior to any additional borrowings under the credit agreement, the ratio of current assets to current liabilities be not less than 1.00 to 1.00. As a result of this new condition to additional borrowings, the Company is currently unable to borrow additional amounts under the credit agreement. The third amendment also increased the interest rate payable under the credit agreement to either (i) the greater of the one month LIBOR plus 1.00% or a domestic bank rate, plus in either case an applicable margin of 0.75% to 1.75% based on utilization, or (ii) a sliding scale from the one, two, three or six month LIBOR, plus an applicable margin of 2.00% to 3.00% based on utilization, and provided for the payment of an amendment fee.

The Company and the administrative agent entered into the fourth amendment to the credit agreement (the "fourth amendment") dated as of April 14, 2009. In addition to waiving compliance with certain restrictive covenants, the fourth amendment reduced our borrowing base as described above.

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 9—Long-Term Debt Obligations

Long-term debt and capital lease obligations consist of the following:

	December 31,	
	2008	2007
	(In thousands)	
Note payable to a bank with interest at 6.875% until December 15, 2008 when it goes to Wells Fargo prime plus 1/2%. On November 15, 2008 the rate changed from a fixed rate of 6.875% to a variable rate. As of December 31, 2008 this variable rate was 4.75%. The note is due in monthly installments through November 15, 2015 when unpaid principal and interest are due. The note is collateralized by the building	\$763	\$786
Less current portion	<u>(30)</u>	<u>(23)</u>
Total	<u>\$733</u>	<u>\$763</u>

The following are future minimum obligations for long-term debt as of December 31, 2008 (in thousands):

Years Ending December 31:	
2009	\$ 30
2010	31
2011	33
2012	34
2013	36
Thereafter	<u>599</u>
Total	<u>\$763</u>

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 10—Fair Value Measurements

Effective January 1, 2008, the Company adopted SFAS No. 157, “Fair Value Measurements” for all financial assets and liabilities measured at fair value on a recurring basis. The statement establishes a framework for measuring fair value and requires enhanced disclosures about fair value measurements. SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The statement establishes market or observable inputs as the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The statement establishes a hierarchy for grouping these assets and liabilities, based on the significance level of the following inputs:

- Level 1—Quoted prices in active markets for identical assets or liabilities;
- Level 2—Quoted prices in active markets for similar assets and liabilities, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations whose inputs are observable or whose significant value drivers are observable;
- Level 3—Significant inputs to the valuation model are unobservable. The following is a listing of the Company’s assets and liabilities required to be measured at fair value on a recurring basis and where they are classified within the hierarchy as of December 31, 2008 (in thousands):

	<u>Level 1</u>	<u>Level 2</u>	<u>Level 3</u>	<u>Total</u>
Assets				
Oil and gas derivative instruments	\$—	\$4,345	\$—	\$4,345
Total	\$—	\$4,345	\$—	\$4,345

A financial asset or liability is categorized within the hierarchy based upon the lowest level of input that is significant to the fair value measurement. The Company’s valuation methodologies for oil and gas derivative instruments, which are measured at fair value and are included in the accompanying balance sheet, are listed below.

The Company uses Level 2 inputs to measure the fair value of oil and gas derivative instruments. The fair value is based on interpolated data. The Company uses an industry standard model that considers various inputs, including (a) quoted forward prices for the specific commodity and area which was hedged, (b) volatility factors with consistent time data that correlates to the remaining life of the derivative instruments and (c) time value. The Company believes that this approach provides a reasonable, non-biased and consistent methodology for valuing oil and gas derivative instruments. In addition, the Company also evaluates company credit risk and counterparty credit risk to determine fair value of the asset or liability and further action as needed.

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 11—Income Taxes

The provision for income taxes consists of the following:

	December 31,		
	2008	2007	2006
	(In thousands)		
Current income tax expense	\$ —	\$ —	\$ —
Deferred income tax expense (benefit)	8,963	7,765	628
Change in valuation allowance	(8,963)	(7,765)	(628)
Total income tax benefit	\$ —	\$ —	\$ —

The effective income tax rate varies from the statutory federal income tax rate as follows:

	December 31,		
	2008	2007	2006
Federal income tax rate	(34)%	(34)%	(34)%
Change in valuation allowance and other	34	34	34
Effective tax rate	—%	—%	—%

The significant temporary differences and carry-forwards and their related deferred tax asset (liability) and deferred tax asset valuation allowance balances are as follows:

	December 31,		
	2008	2007	2006
	(In thousands)		
Deferred tax assets			
Net operating loss carry-forward	\$ 13,862	\$10,996	\$2,954
Oil and gas properties	3,543	—	—
Property and Equipment	284	—	—
Percentage Depletion	463		
Other	302	141	92
Gross deferred tax assets	18,454	11,137	3,046
Deferred tax liabilities			
Oil and gas properties	—	2,893	1,699
Property and equipment	—	41	127
Unrealized gain on hedges	1,477	189	971
Gross deferred tax liabilities	1,477	3,123	2,797
Net deferred tax asset	16,977	8,014	249
Less valuation allowance	(16,977)	(8,014)	(249)
Deferred tax asset	\$ —	\$ —	\$ —

For income tax purposes at December 31, 2008, the Company has net operating loss carry-forwards of approximately \$40,771,000, which expire in 2028. The Company has provided for a valuation

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 11—Income Taxes (Continued)

allowance of \$16,977,000 due to the uncertainty of realizing the tax benefits from its net deferred tax asset.

On January 1, 2007, the Company adopted the provisions of FIN 48, “Accounting for Uncertainty in Income Taxes.” FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 requires that the Company recognize in its financial statements only those tax positions that are “more-likely-than-not” of being sustained as of the adoption date, based on the technical merits of the position. As a result of the implementation of FIN 48, the Company performed a comprehensive review of its material tax positions in accordance with recognition and measurement standards established by FIN 48.

As a result of this review, the Company did not identify any material deferred tax assets that required adjustment. As of January 1, 2007, the date of adoption of FIN 48, and as of December 31, 2008 and 2007, the Company had not recorded any material uncertain tax benefits.

The Company’s policy is to recognize interest and penalties related to uncertain tax benefits in income tax expense. As of December 31, 2008, the Company has not recognized any interest or penalties in its statement of operations or statement of financial position.

The Company is subject to the following material taxing jurisdictions: U.S. federal. The Company also has material operations in the state of Wyoming; however, Wyoming does not impose a corporate income tax. The tax years that remain open to examination by the U.S. Internal Revenue Service are years 2004 through 2008. Due to the Company’s net operating loss carry forwards, the Internal Revenue Service may also adjust the amount of loss realizable under examination back to 2003.

Note 12—Stock Option Plans

Options Under Employee Option Plans

The Company has adopted stock option plans containing both incentive and non-statutory stock options. All options allow for the purchase of common stock at prices not less than the fair market value of such stock at the date of grant. If the option holder owns more than 10% of the total combined voting power of all classes of the Company’s stock, the exercise price cannot be less than 110% of the fair market value of such stock at the date of grant.

Options granted under the plans become vested as directed by the Company’s Board of Directors and generally expire seven or ten years after the date of grant, unless the option holder owns more than 10% of the total combined voting power of all classes of the Company’s stock, in which case the non-statutory stock options must be exercised within five years of the date of grant. The Company granted 0, 120,000 and 455,000 options to employees under the plans during the years ended December 31, 2008, 2007, and 2006, respectively. At December 31, 2008, there were 1,684,208 shares available for grant under the plans.

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 12—Stock Option Plans (Continued)

The options granted all vest as follows:

Year 1	20%
Year 2	30
Year 3	<u>50</u>
	<u>100%</u>

At December 31, 2008, the Company had unvested options to purchase 126,250 shares with a weighted average grant date fair value of \$0.7 million. During the year ended December 31, 2008, the Company did not grant employee options and recognized compensation expense of approximately \$613,000 for options granted in prior years. The Company will recognize compensation expense relating to non-vested options granted after January 1, 2006 of approximately \$324,000 ratably over the next 2 years.

The following table summarizes stock option activity for the years ended December 31, 2008, 2007 and 2006:

	<u>Number of Shares</u>	<u>Weighted Average Exercise Price per Share</u>	<u>Weighted Average Remaining Contractual Life</u>	<u>Aggregate Intrinsic value</u>
Outstanding, December 31, 2005	645,000	\$ 4.56		
Granted	455,000	9.57		
Canceled or forfeited	<u>(65,000)</u>	<u>5.92</u>		
Outstanding, December 31, 2006	1,035,000	\$ 6.68		
Granted	120,000	10.03		
Canceled or forfeited	<u>(284,000)</u>	<u>8.47</u>		
Outstanding, December 31, 2007	871,000	\$ 6.56		
Canceled or forfeited	<u>(194,750)</u>	<u>\$ 8.74</u>		
Outstanding, December 31, 2008	<u>676,250</u>	<u>\$ 5.93</u>	<u>3.40</u>	<u>\$ 0</u>
Exercisable at December 31, 2008	<u>550,000</u>	<u>\$ 5.45</u>	<u>3.14</u>	<u>\$ 0</u>

The following table summarizes information about stock options outstanding at December 31, 2008:

<u>Exercise Prices</u>	<u>Options Outstanding</u>			<u>Options Exercisable</u>	
	<u>Number of Shares Outstanding</u>	<u>Weighted Average Remaining Contractual Life</u>	<u>Number Exercisable</u>	<u>Weighted Average Exercise Price</u>	<u>Fair Value Determination</u>
\$4.00	137,500	1.8 years	137,500	\$ 4.00	Black-Scholes (minimum value)
\$4.80	282,500	3.3 years	282,500	\$ 4.80	Black-Scholes (minimum value)
\$5.20	112,500	4.1 years	56,250	\$ 5.20	Black-Scholes
\$8.40	25,000	5.5 years	5,000	\$ 8.40	Black-Scholes
\$11.00	118,750	4.5 years	68,750	\$11.00	Black-Scholes
	<u>676,250</u>		<u>550,000</u>		

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 12—Stock Option Plans (Continued)

The following table summarizes stock option activity for the years ended December 31, 2008, 2007 and 2006:

Restricted Stock

The Company has an incentive program whereby grants of restricted stock have been awarded to members of the Board of Directors and certain employees. Restrictions and vesting periods for the awards are determined at the discretion of the Board of Directors and are set forth in the award agreements.

On July 1, 2008 the Company issued 86,650 shares of restricted stock to certain employees. On August 8, 2008 an additional 10,500 shares were issued to certain employees. In addition, on August 25, 2008, the Company issued 60,000 shares of restricted stock to executive officers of the Company. These shares will vest 33.34%, 33.33% and 33.33% on the first, second and third anniversary of the grant date. Also the Company issued 87,500 shares on August 25, 2008 to non employee directors which vested on December 31, 2008. The Company, recognized an expense of approximately \$571,000, \$356,000 and \$79,000 for the years ended December 31, 2008, 2007 and 2006 respectively, based on the fair value of the vested shares during the period.

A summary of the status and activity of the restricted stock for the years ended December 31, 2008 and 2007 is presented below.

	Shares	Weighted-Average Grant-Date Fair Value
Non-vested at December 31, 2005	—	\$11.00
Granted	36,360	11.00
Forfeited	(9,090)	11.00
	27,270	\$11.00
Non-vested at December 31, 2006	27,270	\$11.00
Granted	155,500	8.41
Forfeited	(17,050)	9.67
	(9,090)	11.00
Vested	(9,090)	11.00
Non-vested at December 31, 2007	156,630	\$ 8.57
Granted	244,650	2.79
Forfeited	(70,828)	6.41
Vested	(126,875)	4.71
Non-vested at December 31, 2008	203,577	\$ 4.78

As of December 31, 2008, the Company had \$0.9 million of unrecognized share-based compensation expense related to non-vested stock awards, which is expected to be amortized over the remaining period of 4 years.

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 13—Redeemable Preferred Stock

Series A Redeemable Preferred Stock

The Company is authorized by the certificate of incorporation to issue up to 25,000,000 shares of preferred stock in one or more series, having rights senior to the shares of common stock. As of December 31, 2008 and 2007, there were no shares of preferred stock issued and outstanding. All of the issued and outstanding shares of the Company's Series A Redeemable Preferred Stock Shares ("Preferred Stock") with a par value of \$0.01 were redeemed with proceeds from the Company's April 2006 private placement. Shares of the Preferred Stock had a liquidation value of \$100 per share and had preference to shares of the Company's common stock. Through the period ending on the seventh anniversary of the issue date at which time the dividends would have accrued at 12.5%, the Preferred Stock would have accrued dividends at the rate of 10.5% per annum compounded quarterly. The Preferred Stock had no stated maturity date. Holders of Preferred Stock had the right to vote on all matters voted on by holders of common stock.

During the years ended December 31, 2008, 2007 and 2006, the Company issued no shares of Preferred Stock.

Note 14—Stockholders' Equity

Common Stock

As of December 31, 2008, there were 29,193,573 shares of common stock issued and outstanding. The Company is authorized to issue 100,000,000 shares of common stock, par value \$0.01.

At formation, the Company issued an aggregate of 3,750,000 shares of common stock, par value \$0.01 per share, in equal portions to a subsidiary of Carrizo and to Rocky Mountain Gas Inc., a former subsidiary of U.S. Energy, in exchange for the contribution of interests in approximately 81,000 gross (40,000 net) acres, including proved producing properties and undeveloped leaseholds, valued at \$15.0 million. The 1,875,000 shares held by Rocky Mountain Gas were transferred to its affiliates, U.S. Energy and Crested Corp., in May 2005. The Company issued an additional 1,250,000 shares of common stock at formation to CSFB in exchange for a cash contribution of \$5.0 million minus offering costs of \$113,000. On November 18, 2005, the Company issued an additional 750,000 shares of common stock to CSFB in connection with the exercise of Series B warrants. On November 30, 2005, Gary W. Uhland, our former President, exercised options to acquire 50,000 shares of our common stock and the Company received \$167,000.

In April 2006, the Company completed a private placement, exempt from registration under the Securities Act, of 12,835,230 shares of common stock to qualified institutional buyers, non-U.S. persons and accredited investors at a price of \$11.00 per share (gross proceeds of \$141.2 million), or \$10.23 per share net of the initial purchaser's discount and placement fee. The gross proceeds were used to pay \$11.3 million in placement fees and offering costs, \$53.6 million for the redemption of all outstanding shares of Series A Redeemable Preferred Stock and all unpaid accrued dividends, \$27.0 million for the acquisition of undeveloped assets in the Green River Basin, \$16.3 million for the repurchase of 1,593,783 shares of common stock from CSFB and our former President, and \$33.0 million for future capital expenditures and general corporate purposes.

In May 2007, the Company completed an initial public offering of an aggregate of 3,750,000 shares of common stock at a price per share of \$9.00, or \$8.37 net of underwriters' discounts and commissions. In June 2007, the underwriters partially exercised their over-allotment option to purchase

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 14—Stockholders' Equity (Continued)

258,614 shares of the Company's common stock from certain selling stockholders. The Company received proceeds of approximately \$29.5 million from its initial public offering, net of underwriters' discount and commissions and additional out of pocket offering costs of approximately \$1.9 million. The proceeds were used to pay down the \$7.0 million outstanding under the Credit Agreement and will be used for capital expenditures, infrastructure development and general corporate purposes.

Note 15—Commitments and Contingencies

Operating Lease

Upon purchase of the building in August 2005, Pinnacle was assigned the lease agreements for existing tenants in the building. The leases expire from January 2010 to December 2013. Future minimum lease income under noncancelable operating leases is as follows:

Year Ending December 31:	
2009	\$108,000
2010	60,000
2011	60,000
2012	60,000
2013	<u>60,000</u>
Total minimum lease payments	<u>\$348,000</u>

Gas Gathering Contracts

The Company has entered into gas gathering and compression agreements with service providers in order to compress and transport its gas to the point of sale. Compression agreements and gathering agreements are based on a fee per Mcf either compressed or gathered. The Company accounts for these fees as a marketing and transportation expense. The Company does not pay or charge marketing fees associated with the movement and sale of natural gas.

Employment Agreements

The Company entered into new employment agreements with the Chief Executive Officer (Mr. Schoonmaker) and Chief Financial Officer (Mr. Barnes) on July 20, 2007, effective January 1, 2007. The initial term of these agreements is one year and the agreements will automatically renew for additional one-year terms unless either party gives 60 days prior written notice. Under Mr. Schoonmaker's employment agreement, he is entitled to an initial base salary of \$250,000, subject to annual adjustment, and an annual bonus of up to 1.0 times his then current base salary, payable in cash or in stock. Under Mr. Barnes' employment agreement, he is entitled to an initial base salary of \$200,000, subject to annual adjustment, and an annual bonus of up to 0.75 times his then current base salary, payable in cash or in stock.

If either executive's employment is terminated by the Company without cause or by either executive for good reason, the executive will be entitled to severance benefits which will include a lump sum payment equal to the sum of (i) 1.0 times his annual base salary plus (ii) 18.0 times the monthly health savings account contribution last made by us for his benefit, and the payment of a pro-rated bonus. Additionally, if either executive's employment is terminated by us without cause or by either

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 15—Commitments and Contingencies (Continued)

executive for good reason or due to retirement, in each case within one year following a change of control of us, the executive will be entitled to severance benefits which will include a lump sum payment equal to 1.5 times his annual base salary and the payment of a pro-rated bonus. In each case, any and all stock options, restricted stock awards and other equity compensation awards held by the executive will immediately vest and become exercisable. In the event that either executive's employment is terminated within six months preceding or following a change of control due to a non-renewal of his employment agreement by us, the executive will be entitled to the same change of control severance benefit described above.

Litigation

From time to time, Pinnacle is subject to legal proceedings and claims that arise in the ordinary course of its business. In addition, like other natural gas and oil producers and marketers, Pinnacle's operations are subject to extensive and rapidly changing federal and state environmental, health and safety and other laws and regulations governing air emissions, wastewater discharges, and solid and hazardous waste management activities. As a result, it is extremely difficult to reasonably quantify future environmental and regulatory related expenditures.

The following represent legal actions in which Pinnacle is involved. No assurance can be given that these legal actions will be resolved in Pinnacle's favor. However, Management believes, based on its experiences to date, that these matters will not have a material adverse impact on Pinnacle's business, financial position or results of operations.

Pinnacle, together with the State of Montana, the Montana Department of Environmental Quality, the Montana Board of Oil and Gas Conservation and the Department of Natural Resources, were named as defendants in a lawsuit (Civil Cause No. DV-05-27) filed on May 19, 2005 in the Montana 22nd Judicial District Court, Bighorn County by Diamond Cross Properties, LLC relating to the Coal Creek POD. The plaintiff is a surface owner with properties located in Big Horn County and Rosebud County, Montana where Pinnacle serves as operator and owns a working interest in the minerals under lease. The plaintiff sought to permanently enjoin the State of Montana and its administrative bodies from issuing licenses or permits, or authorizing the removal of ground water from under the plaintiff's ranch. In addition, the plaintiff further sought to preliminarily and permanently enjoin Pinnacle on the basis that Pinnacle's operations lacked adequate safeguards required under the Montana state constitution. On August 25, 2005, the district judge issued an order denying without prejudice the application for temporary restraining order and preliminary injunction requested by the plaintiff. The case was appealed by the plaintiff to the Montana Supreme Court. On November 16, 2005, the Montana Supreme Court issued an order that denied enjoining the Coal Creek POD, and subsequently, the Montana Supreme Court remanded the case back to the district court for a decision on the merits.

Pinnacle, together with the defendants above, were also named as defendants in a lawsuit (Civil Cause No. DV-05-70) filed on September 21, 2005 in the Montana 22nd Judicial District Court, Bighorn County by Diamond Cross Properties, LLC relating to the Dietz POD. The plaintiff sought similar relief as in the Coal Creek POD suit.

The two cases were combined.

On July 14, 2008, the district court issued a summary judgment order in the combined case, and the order was subsequently entered as a judgment on August 15, 2008. As a result, we have continued our operations in the two project areas. To date, there has been no appeal by the plaintiff.

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 15—Commitments and Contingencies (Continued)

Pinnacle was named as a defendant in two related lawsuits, Civil Action No. 06CV0047J filed on March 30, 2006 in the United States District Court, Wyoming by Burning Rock Energy, LLC and Case No. 06-CV-01627-MDM-MEH filed on April 25, 2006 in the United States District Court for the District of Colorado by John R. Behrmann, et al., claiming various contract and tort claims against Pinnacle relating to a like-kind exchange between Pinnacle and the plaintiffs of approximately 1,000 acres of leased acreage in January 2004. The plaintiffs claimed, in part, that the leases transferred by Pinnacle to Burning Rock did not terminate upon nonpayment of shut-in rentals and further, that Pinnacle trespassed by releasing from the original lessors the properties originally transferred to Burning Rock under the exchange agreement. In April 2007, Pinnacle settled these claims with the plaintiffs and both lawsuits have been dismissed. The settlement arrangement included a \$500,000 payment by Pinnacle to Burning Rock together with an assignment by Pinnacle to Burning Rock of a 69.5% carried working interest in the disputed leased acreage.

Regulations

The Company's oil and gas operations are subject to various federal, state and local laws and regulations. The Company could incur significant expense to comply with the new or existing laws and non-compliance could have a material adverse effect on the Company's operations. In December 2007, the U.S. Bureau of Land Management imposed a permitting application fee of \$4,000 per well drilled on federal lands.

Environmental

The Company produces significant amounts of water from its wells. If future wells produce water of a lesser quality than allowed under state laws or if water is produced at rates greater than the Company can dispose of, the Company could incur additional costs to dispose of the water.

Note 16—Major Customers

The following is a table summarizing the percentage of sales made to each purchaser that accounted for over 10% of the Company's gas sales for the years ended December 31, 2008, 2007 and 2006. The loss of any of these customers could have a material adverse effect on the Company's operations.

	December 31,		
	2008	2007	2006
Enserco	46%	58%	66%
Western Gas Resources	—	—	21%
United Energy Trading	54%	36%	11%
Cantera	—	5%	—
Other	—	1%	2%
	<u>100%</u>	<u>100%</u>	<u>100%</u>

Note 17—Fair Value of Financial Instruments

The carrying values of the Company's cash and cash equivalents, accounts receivable, accounts payable, accrued liabilities, and revenue distributions payable represent the fair value due to the short-term nature of the accounts. Long-term debt at December 31, 2008 and 2007, with a carrying value of approximately \$763,000 and \$786,000, respectively, is estimated to approximate fair value as the terms are comparable to current market terms.

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 17—Fair Value of Financial Instruments (Continued)

The fair value of the Company's derivatives are estimated using various models and assumptions related to the estimated terms of the instruments, volatility of the price of the Company's common stock, interest rates and the probability of conversion, among other items.

Note 18—Supplemental Oil and Gas Information

Estimated Proved Oil and Gas Reserves (Unaudited)

Proved oil and gas reserves are estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. There are uncertainties inherent in estimating quantities of proved oil and gas reserves, projecting future production rates, and timing of development expenditures. Accordingly, reserve estimates often differ from the quantities of oil and gas that are ultimately recovered.

All of the Company's proved reserves are located in the United States. The following information about the Company's proved and proved developed oil and gas reserves was developed from reserve reports prepared by independent reserve engineers:

	Natural Gas (Mcf)
Proved reserves as of December 31, 2005	27,038,629
Purchases of reserves in place	329,792
Extension, discoveries and other additions	7,954,735
Revisions of previous estimates(1)	(12,621,500)
Production	(2,413,130)
Proved reserves as of December 31, 2006	20,288,526
Purchases of reserves in place	—
Extension, discoveries and other additions	7,673,024
Revisions of previous estimates(1)	1,147,906
Production	(3,388,792)
Proved reserves as of December 31, 2007	25,720,664
Purchases of reserves in place	95,300
Extension, discoveries and other additions	9,161,500
Revisions of previous estimates(1)	(3,388,139)
Production	(3,869,925)
Proved reserves as of December 31, 2008	27,719,400
Proved developed reserves as of December 31, 2006	7,879,271
Proved developed reserves as of December 31, 2007	10,457,663
Proved developed reserves as of December 31, 2008	15,412,429

(1) The revision in 2008 is primarily due to the price decrease on December 31, 2008 to \$4.61, based on the Rocky Mountain CIG Index, from the December 31, 2007 price of \$6.04. The revision in

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 18—Supplemental Oil and Gas Information (Continued)

2007 is primarily due to the price increase on December 31, 2007 to \$6.04, based on the Rocky Mountain CIG Index, from the December 31, 2006 price of \$4.46. The revision in 2006 is primarily due to the price decrease from December 31, 2005 of \$7.72, based on the Rocky Mountain CIG Index, to the December 31, 2006 price of \$4.46.

Aggregate Capitalized Costs

Aggregate capitalized costs relating to the Company's oil and gas producing activities, and related accumulated depreciation, depletion, amortization and ceiling write-down are as follows:

	December 31,	
	2008	2007
	(In thousands)	
Proved oil and gas properties	\$103,038	\$ 72,967
Unproved oil and gas properties	86,827	88,820
Total	189,865	161,787
Less accumulated depreciation, depletion, amortization and ceiling write-down	(68,516)	(39,002)
Net capitalized costs	\$121,349	\$122,785

Costs Incurred in Oil and Gas Producing Activities

Costs incurred in connection with the Company's oil and gas acquisition, exploration and development activities are as follows:

	December 31,		
	2008	2007	2006
	(In thousands)		
Property acquisition costs			
Proved	\$ 2,197	\$ 1,357	\$ 7,283
Unproved	2,206	1,146	30,316
Total property acquisition costs	4,403	2,503	37,599
Exploration costs	1,186	2,579	23,498
Development costs	22,154	16,124	7,496
Asset retirement costs	399	239	863
Total costs	\$28,144	\$21,445	\$69,456

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 18—Supplemental Oil and Gas Information (Continued)

Oil and Gas Operations

Aggregate results of operations in connection with the Company's gas producing activities are shown below:

	December 31,		
	2008	2007	2006
	(In thousands)		
Revenues	\$ 22,441	\$ 13,141	\$12,575
Production costs and taxes	13,085	9,582	6,153
Impairment of oil and gas properties	21,521	18,225	—
Depletion	8,061	5,518	6,015
Accretion of asset retirement obligations	248	208	162
Results of operations from producing activities (excluding corporate overhead and interest costs)	<u>\$ (20,474)</u>	<u>\$ (20,392)</u>	<u>\$ 245</u>
Depletion per MCF equivalent	<u>\$ 2.08</u>	<u>\$ 1.63</u>	<u>\$ 2.49</u>

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Unaudited)

Future gas sales and production and development costs have been estimated using prices and costs in effect at the end of the period indicated, except in those instances where the sale of natural gas is covered by contracts, as required by SFAS No. 69, "Disclosures about Oil and Gas Producing Activities." SFAS No. 69 requires that net cash flow amounts be discounted at 10%. This information does not represent the fair market value of the Company's proved oil and gas reserves.

	December 31,		
	2008	2007	2006
	(In thousands)		
Future cash inflows	\$105,385	\$123,380	\$ 73,376
Future production costs	(41,764)	(42,388)	(25,975)
Future development costs	(16,352)	(15,952)	(12,596)
Future income tax expense	(669)	(5,236)	(2,950)
Future cash flows	46,600	59,804	31,855
10% annual discount for estimated timing on cash flows	<u>(14,435)</u>	<u>(21,245)</u>	<u>(9,471)</u>
Standardized measure of discounted future cash flows	<u>\$ 32,105</u>	<u>\$ 38,559</u>	<u>\$ 22,384</u>

The following table presents the average year-end market gas price used to compute future cash inflows for each period:

	December 31,		
	2008	2007	2006
Weighted average gas price per Mcf	<u>\$4.605</u>	<u>\$6.040</u>	<u>\$4.460</u>

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 18—Supplemental Oil and Gas Information (Continued)

Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the Company's proved oil and gas reserves at December 31, 2008, 2007 and 2006 assuming continuation of existing economic conditions.

The following reconciles the change in the standardized measure of discounted future net cash flow:

	December 31,		
	2008	2007	2006
	(In thousands)		
Beginning of period	\$ 38,559	\$22,384	\$ 43,685
Net change from purchases of minerals in place	100	—	760
Net change in sales and transfer prices, net of production costs	(16,775)	8,391	(40,437)
Revision of previous quantity estimates	(7,928)	13,166	(7,018)
Extensions, discoveries and other additions	9,997	—	—
Sales of oil and gas, net of production costs	(9,355)	(3,559)	(6,043)
Development cost incurred, previously estimated . . .	(400)	(3,021)	(8,044)
Net change in income taxes	4,566	(2,286)	11,908
Changes in future development costs	8,961	951	21,719
Accretion of discount	4,380	2,533	5,854
End of period	<u>\$ 32,105</u>	<u>\$38,559</u>	<u>\$ 22,384</u>

Future income tax expenses are computed by applying the appropriate period-end statutory tax rates to the future pretax net cash flow relating to the Company's proved oil and gas reserves, less the tax basis of the related properties. The future income tax expenses do not give effect to tax credits, allowances, or the impact of general and administrative costs of ongoing operations relating to the Company's proved gas reserves.

Note 19—Quarterly Financial Data (Unaudited)

The following is a summary of the unaudited quarterly financial data for the years ended December 31, 2007 and 2006 (in thousands, except per share data):

	Three Months Ended			
	March 31, 2008	June 30, 2008	September 30, 2008	December 31, 2008
Year ended December 31, 2008:				
Revenues	5,661	7,573	5,684	3,523
Cost of revenue and expenses	(6,888)	(8,919)	(7,601)	(27,193)
Net Income (Loss)	(5,648)	(3,874)	8,939	(21,154)
Basic net income (loss) per share	(0.19)	(0.13)	0.31	(0.72)
Diluted net income (loss) per share	(0.19)	(0.13)	0.30	(0.72)

PINNACLE GAS RESOURCES, INC.
Notes to Financial Statements (Continued)

Note 19—Quarterly Financial Data (Unaudited) (Continued)

	Three Months Ended			
	March 31, 2007	June 30, 2007	September 30, 2007	December 31, 2007
Year ended December 31, 2007:				
Revenues	3654	3,346	2,722	3,329
Cost of revenue and expenses	(21,699)	(6,457)	(5,773)	(5,573)
Net loss	(18,150)	(2,071)	(1,151)	(2,005)
Basic net loss per share	(0.72)	(0.08)	(0.04)	(0.07)
Diluted net loss per share	(0.72)	(0.08)	(0.04)	(0.07)

Note 20—Subsequent Events

The Company and the administrative agent entered into the fourth amendment to the credit agreement dated as of April 14, 2009. The fourth amendment waived compliance with the current ratio covenant as of December 31, 2008 and March 31, 2009, and with certain other restrictive covenants related to overdue accounts payable, permitted liens and permitted debt until the next borrowing base redetermination expected in the fall of 2009, subject to certain financial caps.

In March 2009, the Company hedged 2,500 MMBtu per day from May 2009 through April 2010 at a price of \$3.445 per MMBtu based on the CIG Inside FERC published price.

In March 2009, the Company hedged 2,000 MMBtu per day from January 2010 through December 2010 at a price of \$4.475 per MMBtu based on the CIG Inside FERC published price.

In April 2009, the Company sold its interest in approximately 800 net undeveloped acres in the Arvada prospect in Wyoming to an unrelated third party and sold certain of its gas gathering assets in the Cabin Creek area of Wyoming to Big Horn Gas Gathering, L.L.C., the field operator of such assets. The Company's aggregate net proceeds from these transactions were approximately \$3.2 million. The Company used part of these proceeds to repay the Company's outstanding indebtedness under its credit facility to \$9.0 million as of April 14, 2009.

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

None.

ITEM 9A(T) CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Our principal executive officer and principal financial officer are responsible for establishing and maintaining adequate disclosure controls and procedures. Based on their evaluation as of the end of the fiscal year ended December 31, 2008, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended, or the Exchange Act) are effective to ensure that information required to be disclosed in reports that we file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms.

Internal Control Over Financial Reporting

Our principal executive officer and principal financial officer are responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is defined in Rule 13a-15(f) or 15d-15(f) promulgated under the Exchange Act as a process designed by, or under the supervision of, the company's principal executive and principal financial officers and effected by the company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and 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 could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In accordance with Item 308 of Regulation S-K, management is required to provide an annual report regarding internal controls over our financial reporting. This report, which includes management's assessment of the effectiveness of our internal controls over financial reporting, follows below.

Our management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2008. In making this assessment, our management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework.

Based on our assessment, management believes that, as of December 31, 2008, our internal control over financial reporting is effective based on those criteria.

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 temporary rules of the SEC that permit a company to provide only management's report in this annual report.

There were no changes in our internal controls over financial reporting or in other factors during the fourth quarter of 2008 that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting. The certifications of our general partner's CEO and CFO required under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 have been included as exhibits to this report on Form 10-K.

ITEM 9B *OTHER INFORMATION*

None.

PART III

ITEM 10 *DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE*

The information required by this Item 10 is incorporated herein by reference to the "Proposal One: Election of Directors," "Management," "Code of Ethics," "Section 16(a) Beneficial Ownership Reporting Compliance" and "Audit Committee" sections of the definitive Proxy Statement relating to our 2009 Annual Meeting of Stockholders.

ITEM 11 *EXECUTIVE COMPENSATION*

The information required by this Item 11 is incorporated herein by reference to the "Executive Compensation" section of the definitive Proxy Statement relating to our 2009 Annual Meeting of Stockholders.

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

The information required by this Item 12 is incorporated herein by reference to the "Security Ownership of Certain Beneficial Owners and Management" section of the definitive Proxy Statement relating to our 2009 Annual Meeting of Stockholders.

ITEM 13 *CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE*

The information required by this Item 13 is incorporated herein by reference to the "Certain Relationships and Related Transactions" and "Director Independence" sections of the definitive Proxy Statement relating to our 2009 Annual Meeting of Stockholders.

ITEM 14 *PRINCIPAL ACCOUNTING FEES AND SERVICES*

The information required by this Item 14 is incorporated herein by reference to the "Proposal Two: Ratification of Ehrhardt Keefe Steiner & Hottman PC as our Independent Auditor" section of the definitive Proxy Statement relating to our 2009 Annual Meeting of Stockholders.

PART IV

ITEM 15 EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) Financial Statements

Included in Item 8 of this annual report:

Report of Independent Registered Public Accounting Firm	66
Balance Sheets as of December 31, 2008 and 2007	67
Statements of Operations for the years ended December 31, 2008, 2007 and 2006	68
Statements of Cash Flows for the years ended December 31, 2008, 2007 and 2006	69
Statements of Redeemable Preferred Stock and Stockholders' Equity for the years ended December 31, 2008, 2007 and 2006	70
Notes to Financial Statements	71

(a)(2) Financial Statement Schedules

None.

(a)(3) Exhibits

The following documents are filed as exhibits to this annual report:

Exhibit Number	Description
2.1	— Amended and Restated Agreement and Plan of Merger, dated as of February 6, 2008, among Quest Resources Corporation, Pinnacle Gas Resources, Inc. and Quest MergerSub, Inc. (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K (File No. 000-17371) filed by Quest Resource Corporation on February 6, 2008).
3.1	— Second Amended and Restated Certificate of Incorporation of Pinnacle Gas Resources, Inc. (incorporated by reference to Exhibit 3.1 to the Registration Statement on Form S-1 (File No. 333-133983) filed by Pinnacle Gas Resources, Inc. on May 10, 2006).
3.2	— Amended and Restated Bylaws of Pinnacle Gas Resources, Inc. (incorporated by reference to Exhibit 3.2 to the Registration Statement on Form S-1 (File No. 333-133983) filed by Pinnacle Gas Resources, Inc. on May 10, 2006).
4.1	— Amended and Restated Securityholders Agreement, dated February 16, 2006 (incorporated by reference to Exhibit 4.1 to the Registration Statement on Form S-1 (File No. 333-133983) filed by Pinnacle Gas Resources, Inc. on May 10, 2006).
4.2	— Registration Rights Agreement, dated April 11, 2006 (incorporated by reference to Exhibit 4.2 to the Registration Statement on Form S-1 (File No. 333-133983) filed by Pinnacle Gas Resources, Inc. on May 10, 2006).
10.1	— Termination of AMI Agreement, dated April 11, 2006, by and among Pinnacle Gas Resources, Inc., CCBM, Inc., Carrizo Oil & Gas, Inc., U.S. Energy Corp., Crested Corp. and the CSFB Parties (as defined therein) (incorporated by reference to Exhibit 10.1 to Amendment No. 1 to the Registration Statement on Form S-1 (File No. 333-133983) filed by Pinnacle Gas Resources, Inc. on September 15, 2006).

Exhibit Number	Description
10.2	— Credit Agreement, dated February 12, 2007, by and among Pinnacle Gas Resources, Inc., as Borrower, the Lenders from time to time party thereto and Royal Bank of Scotland plc, individually and as Administrative Agent (incorporated by reference to Exhibit 10.2 to Amendment No. 1 to the Registration Statement on Form S-1 (File No. 333-139556) filed by Pinnacle Gas Resources, Inc. on April 3, 2007).
10.3	— Letter regarding waiver and amendment of Credit Agreement, dated March 9, 2007 (incorporated by reference to Exhibit 10.3 to Amendment No. 1 to the Registration Statement on Form S-1 (File No. 333-139556) filed by Pinnacle Gas Resources, Inc. on April 3, 2007).
10.4	— Purchase and Sale Agreement, dated February 7, 2006, between Kennedy Oil and Pinnacle Gas Resources, Inc. (incorporated by reference to Exhibit 10.5 to Amendment No. 1 to the Registration Statement on Form S-1 (File No. 333-133983) filed by Pinnacle Gas Resources, Inc. on September 15, 2006).
10.5	— Gas Gathering Agreement (Low Pressure Field Gathering) by and among Bitter Creek Pipelines, LLC and Pinnacle Gas Resources, Inc., Quaneco L.L.C. and Dolphin Energy Corporation (incorporated by reference to Exhibit 10.6 to Amendment No. 1 to the Registration Statement on Form S-1 (File No. 333-133983) filed by Pinnacle Gas Resources, Inc. on September 15, 2006).
10.6	— Gas Gathering Agreement (High Pressure Gathering Line) by and among Bitter Creek Pipelines, LLC and Pinnacle Gas Resources, Inc., Quaneco L.L.C. and Dolphin Energy Corporation (incorporated by reference to Exhibit 10.7 to Amendment No. 1 to the Registration Statement on Form S-1 (File No. 333-133983) filed by Pinnacle Gas Resources, Inc. on September 15, 2006).
10.7	— Midstream Transportation Agreement, effective December 1, 2003, by and between Pinnacle Gas Resources, Inc. and Clear Creek Natural Gas, LLC (incorporated by reference to Exhibit 10.8 to Amendment No. 1 to the Registration Statement on Form S-1 (File No. 333-133983) filed by Pinnacle Gas Resources, Inc. on September 15, 2006).
†10.8	— Amended and Restated Stock Incentive Plan, effective February 16, 2006 (incorporated by reference to Exhibit 10.9 to Amendment No. 1 to the Registration Statement on Form S-1 (File No. 333-133983) filed by Pinnacle Gas Resources, Inc. on September 15, 2006).
†10.9	— Form of Stock Option Agreement (incorporated by reference to Exhibit 10.10 to Amendment No. 1 to the Registration Statement on Form S-1 (File No. 333-133983) filed by Pinnacle Gas Resources, Inc. on September 15, 2006).
†10.10	— Form of Restricted Stock Grant Agreement (incorporated by reference to Exhibit 10.11 to Amendment No. 1 to the Registration Statement on Form S-1 (File No. 333-133983) filed by Pinnacle Gas Resources, Inc. on September 15, 2006).
†10.11	— Form of Indemnification Agreement (incorporated by reference to Exhibit 10.13 to Amendment No. 1 to the Registration Statement on Form S-1 (File No. 333-133983) filed by Pinnacle Gas Resources, Inc. on September 15, 2006).

Exhibit Number	Description
10.12	— Purchase/Placement Agreement, dated March 31, 2006, between Pinnacle Gas Resources, Inc. and Friedman, Billings, & Ramsey & Co., Inc. (incorporated by reference to Exhibit 10.18 to the Registration Statement on Form S-1 (File No. 333-133983) filed by Pinnacle Gas Resources, Inc. on May 10, 2006).
*†10.13	— Summary of Director Compensation.
†10.14	— Employment Agreement, dated July 20, 2007, by and between Pinnacle Gas Resources, Inc. and Peter G. Schoonmaker (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-33457) filed by Pinnacle Gas Resources, Inc. on July 24, 2007).
†10.15	— Employment Agreement, dated July 20, 2007, by and between Pinnacle Gas Resources, Inc. and Ronald T. Barnes (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K (File No. 001-33457) filed by Pinnacle Gas Resources, Inc. on July 24, 2007).
†10.16	— Pinnacle Gas Resources, Inc. Management Incentive Plan (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K (File No. 001-33457) filed by Pinnacle Gas Resources, Inc. on July 24, 2007).
10.17	— Letter Agreement by and between Pinnacle Gas Resources, Inc. and the Royal Bank of Scotland, executed as of April 10, 2008, regarding the credit facility dated as of February 12, 2007 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q (File No. 001-33457) filed by Pinnacle Gas Resources, Inc. on May 15, 2008).
10.18	— Second Amendment to Credit Agreement, dated August 4, 2008 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-33457) filed by Pinnacle Gas Resources, Inc. on August 6, 2008).
10.19	— Third Amendment to Credit Agreement, effective September 30, 2008 (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q (File No. 001-33457) filed by Pinnacle Gas Resources, Inc. on November 14, 2008).
†10.20	— Second Amended and Restated Stock Incentive Plan, effective November 11, 2008 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q (File No. 001-33457) filed by Pinnacle Gas Resources, Inc. on November 14, 2008).
*10.21	Fourth Amendment to Credit Agreement dated as of April 14, 2009.
*31.1	— Certification of President and Chief Executive Officer of Pinnacle Gas Resources, Inc. pursuant to Rules 13a-14(a) and 15d-14(a).
*31.2	— Certification of Senior Vice President, Chief Financial Officer and Secretary of Pinnacle Gas Resources, Inc. pursuant to Rules 13a-14(a) and 15d-14(a).
*32.1	— Certification of President and Chief Executive Officer of Pinnacle Gas Resources, Inc. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	— Certification of Senior Vice President, Chief Financial Officer and Secretary of Pinnacle Gas Resources, Inc. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith

† Management contract or compensatory plan or arrangement

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.

PINNACLE GAS RESOURCES, INC.

By: /s/ PETER G. SCHOONMAKER

Name: Peter G. Schoonmaker

Title: *President and Chief Executive Officer*

Date: April 15, 2009

Pursuant to the requirements of the Securities Exchange 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.

<u>Signature</u>	<u>Title</u>	<u>Date</u>
<u>/s/ Peter G. Schoonmaker</u> Peter G. Schoonmaker	President and Chief Executive Officer (Principal Executive Officer) and Director	April 15, 2009
<u>/s/ Ronald T. Barnes</u> Ronald T. Barnes	Senior Vice President, Chief Financial Officer and Secretary (Principal Financial Officer and Principal Accounting Officer)	April 15, 2009
<u>/s/ Thomas G. McGonagle</u> Thomas G. McGonagle	Chairman of the Board of Directors	April 15, 2009
<u>/s/ Robert L. Cabes, Jr.</u> Robert L. Cabes, Jr.	Director	April 15, 2009
<u>/s/ Jeffrey P. Gunst</u> Jeffrey P. Gunst	Director	April 15, 2009
<u>/s/ S. P. Johnson, IV</u> S. P. Johnson, IV	Director	April 15, 2009
<u>/s/ F. Gardner Parker</u> F. Gardner Parker	Director	April 15, 2009
<u>/s/ Susan C. Schnabel</u> Susan C. Schnabel	Director	April 15, 2009