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

FORM 10-K
Amendment 2

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2010

Commission file number 333-125068

HIGH PLAINS GAS, INC.
(Exact name of registrant as specified in its charter)
www.highplainsgas.com

Nevada	**36-36343813**
(State or other jurisdiction of incorporation or organization)	(I. R. S. Employer Identification No.)

Registrant's telephone number, including area code: **(307) 686-5030**

3601 Southern Dr., Gillette, Wyoming 82718
(Address of principal executive offices)

Copies of all communications should be sent to:

Cutler Law Group
3355 W Alabama, Ste 1150
Houston, Texas 77098
Telephone: (713) 888-0040
Facsimile: (800) 836-0714
Email: rcutler@cutlerlaw.com

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

Title of Each Class	Name of Each Exchange on which Registered
None	None

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

Common Stock ($.001 par value)
(Title of Class)

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

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

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

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

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

Indicate by checkmark whether the registrant is a shell company (as defined in Rule 126-2 of the Act)
Yes [ ] No [x]

The aggregate market value of the common equity held by non-affiliates of the registrant as of April 13, 2011 was $63,589,634.

The number of shares of the registrant’s common stock outstanding as of April 13, 2011, was 166,523,602 shares.

High Plains Gas, Inc.

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Cautionary Notice Regarding Forward-Looking Statements

The following discussion is included to inform our existing and potential security holders generally of some of the risks and uncertainties that can affect us and to take advantage of the "safe harbor" protection for forward-looking statements afforded under federal securities laws.

From time to time, our management or persons acting on our behalf make forward-looking statements to inform existing and potential security holders about us. This Annual Report on Form 10K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities and Exchange Act of 1934, as amended, which are subject to a number of risks and uncertainties, many of which are beyond our control. These statements by nature are subject to certain risks, uncertainties and assumptions and will be influenced by various factors. Should any of the assumptions underlying a forward-looking statement prove incorrect, actual results could vary materially. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from our expectations include, but not limited to, our assumptions about:

- business and financial strategy;
- oil and natural gas reserves;
- lower oil and natural gas prices negatively affecting our ability to borrow or raise capital, or enter into joint venture arrangements and potentially requiring accelerated repayment of amounts borrowed under our credit facility;
- declines in the values of our oil and natural gas properties resulting in write-downs;
- exploration and development drilling prospects, inventories, projects and programs;
- ability to obtain industry partners for our prospects on favorable terms to reduce our capital risks and accelerate our exploration activities;
- ability to obtain permits and governmental approvals;
- identified and future drilling locations;
- changing regulatory environment;
- transportation and access to pipelines;
- the ability of our hedge counterparties to fulfill their obligations;
- lease operating expenses and costs related to the acquisition and development of oil and gas properties;
- availability and costs of drilling rigs and field services;
- the impact of current economic and financial conditions on our ability to raise capital;
- general and administrative costs, oilfield services costs and other expenses related to our business;
- technology;

- future operating results; and
- plans, objectives, expectations and intentions.

It is difficult to predict and many of these factors are beyond our ability to control. These factors are not intended to represent a complete list of the general or specific factors that may affect us.

All of these types of statements about our future expectations are "forward-looking statements" within the meaning of applicable Federal Securities Laws, and are not guarantees of future performance. When used herein, the words "may," "will," "should," "anticipate," "believe," "appear," "intend," "plan," "expect," "estimate," "approximate," and similar expressions are intended to identify such forward-looking statements. These statements involve risks and uncertainties inherent in our business, including those set forth in Item 1A under the caption “Risk Factors,” “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and other sections in this Annual Report on Form 10-K for the year ended December 31, 2010, and other filings with the SEC, and are subject to change at any time. Our actual results could differ materially from these forward-looking statements. We undertake no obligation to update publicly any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

We caution you not to place undue reliance on these forward-looking statements. We urge you to carefully review and consider the disclosures made in this Form 10-K and our reports filed with the SEC that attempt to advise interested parties of the risks and factors that may affect our business.

PART I

Item 1. Business

General

High Plains Gas Inc., (“Company,” “we,” “our,” or “us”) is a Rocky Mountain exploration and production company that seeks to enhance shareholder value by executing a long-term growth strategy. We seek to build stockholder value through profitable growth in reserves and production, which will include investing in and profitably developing key existing development programs as well as growth through exploration and acquisitions. We seek high quality exploration and development projects with potential for providing long-term drilling inventories that generate high returns. Substantially all of our revenues are generated through the sale of natural gas at market prices and the settlement of commodity hedges. Our management team has significant experience acquiring and developing E&P assets in the Rocky Mountains and has an extensive network of industry relationships in the region. Through its solid foundation and experience, the Company intends to pursue expansion plans across this region.

Summary of Recent Company History

The Company was originally incorporated in Nevada as Northern Explorations, Ltd. (“Northern Explorations”) on November 17, 2004. From its inception, the Company was engaged in the business of exploration of natural resource properties in the United States. After the effective date of its registration statement filed with the Securities and Exchange Commission (February 14, 2006), the Company commenced quotation on the Over-the-Counter Bulletin Board under the symbol “NXPN.”

On July 28, 2010, the Company entered into an agreement to acquire High Plains Gas, LLC, a Wyoming limited liability company (“High Plains LLC”) (the “Reorganization Agreement). On September 13, 2010, the Company amended its Articles of Incorporation to change its name to High Plains Gas, Inc. and increase its authorized common stock to 250,000,000 shares. Effective October 29, 2010, the Company completed the acquisition of High Plains Gas, LLC, the operating entity for the Company's business. The reorganization has been accounted for as a reverse merger and under the accounting rules for a reverse merger, the historical financial statements and results of operations of High Plains Gas, LLC became those of the company. The symbol was changed on January 20, 2011 to "HPGS" to more accurately reflect the Company's new name. Under the Reorganization Agreement, shareholders and other parties representing what was Northern Explorations retained 26,000,000 shares of the Company's common stock and designees of High Plains LLC were issued 104,000,000 shares of the Company's common stock.

As of September 30, 2010, the Company entered into agreements with Current Energy Partners Corporation, a Delaware Corporation ("Current") and its wholly owned subsidiary CEP M Purchase LLC ("CEP"). In accordance with the terms of the agreements, the Company initially purchased a Convertible Note from Current for the amount of $3,550,000 and also provided assistance with CEP's bonding requirements. The proceeds from the Convertible Note as well as approximately $6,000,000 in bank financing were used (described below) by Current through its subsidiary CEP to purchase a significant resource base and land position from Pennaco Energy, Inc. ("Pennaco"), a wholly owned subsidiary of Marathon Oil Company. The assets consisted of Pennaco's "North & South Fairway" assets located in the Powder River Basin. These properties encompass approximately 155,000 net operated acres (the "Marathon Assets"). The acquisition included many operational capacities including flow lines, transportation rights and production wells both active and idle. The transaction did not transfer deep oil rights, but focused upon mineral rights between the surface and depth above the base Tertiary Paleocene Fort Union Formation, generally above 2,500 feet. Under the original agreement, the Company was appointed to perform the operating duties with respect to the assets as specified in the underlying Purchase and Sale Agreement executed on July 21, 2010 by and among Current, CEP and Pennaco (the "Pennaco Agreement").

On October 18, 2010, the Company, pursuant to the Reorganization Agreement, issued 104,000,000 shares to nine individuals representing 100% of the membership in High Plains LLC and as a result, High Plains LLC became a 100% owned subsidiary of the Company.

On December 8, 2010, the Company signed a definitive Stock Purchase Agreement (the "Purchase Agreement") with Big Cat Energy Corporation ("Big Cat") to purchase 20,000,000 shares of Big Cat's restricted common stock, or approximately 31.3% of the projected issued and outstanding shares, at $0.03 per share for $600,000. The purchase price of $600,000 consisted of a combination of $200,000 cash and 739,180 restricted shares of the Company valued at $400,000. The Purchase Agreement also grants the Company warrants to purchase an additional 10,000,000 shares of restricted common stock of Big Cat at $0.15 per share. If the Company exercised the warrants, it would own 30,000,000 shares of Big Cat's common stock, which represents 40.6% of Big Cat. The warrants have a term of five years from the effective date of the Purchase Agreement. The number of warrants is to be adjusted in the event of a reclassification, change, stock dividend, stock split, combination, reorganization, merger or consolidation affecting the price or number of shares issuable or exercisable under the warrants so as to maintain an approximately equivalent number of shares and exercise price for the warrant holders before and after such a transaction. Any such adjustment is to be made pursuant to official notice from the Company in connection with the transaction. On the closing of this transaction, Big Cat nominated Mark Hettinger, Chairman of the Company, to Big Cat's Board of Directors.

During the fiscal quarter ended December 31, 2010, the Company entered into a $75,000,000 credit facility with Amegy Bank of which $6,000,000 was borrowed to finance the Pennaco Acquisition.

On January 24, 2011, the Company's Board of Directors amended the Company's bylaws to provide for a five member Board of Directors, and appointed Gary Davis, Cordell Fonnesbeck and Alan R. Smith as directors in addition to the already appointed directors, Mark D. Hettinger and Joseph Hettinger.

On February 2, 2011, the Company signed a Purchase and Sale Agreement with J.M. Huber Corporation (the "Huber Purchase Agreement") in which the Company agreed to purchase approximately 313,000 net acres of leasehold and 2,302 wells in the Basin for $35,000,000 (the "Huber Acquisition"). The Company provided $2,000,000 in non-refundable deposits in connection with the Huber Purchase Agreement and later issued 1,500,000 shares of common stock to extend the closing date (which shares will either be returned to the Company or applied to the purchase price at closing).

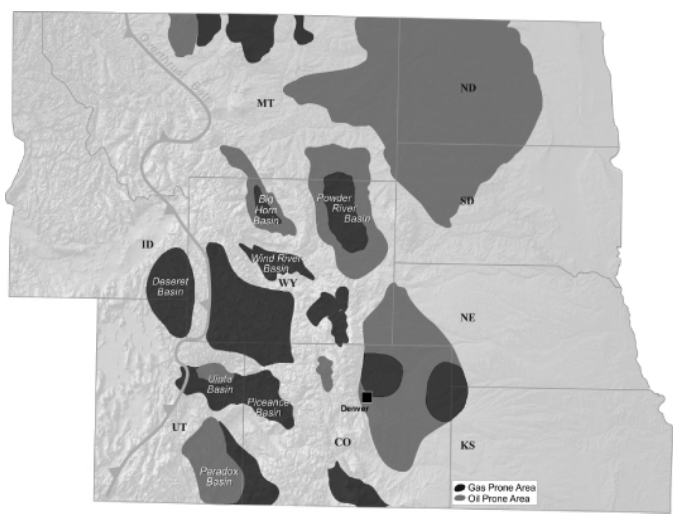
On February 24, 2011, the Company entered into an agreement with Fletcher International, Ltd. (“Fletcher”) pursuant to which it sold Fletcher warrants to purchase $5,000,000 in shares of the Company’s common stock for a purchase price of $1,000,000. The exercise price for Common Stock to be purchased in the warrants issued to Fletcher is the lesser of (i) $1.25 and (ii) the average of the volume weighted average market price for all of the business days in the calendar month immediately preceding the date of the first notice of exercise of the Warrants, but in no event can the exercise price be less than $0.50. The warrants include a cashless exercise provision. The proceeds of the Fletcher warrants were utilized as a deposit for the Huber Purchase Agreement.

On March 31, 2011 the Company signed an amendment to the Huber Purchase Agreement in which both parties agreed to extend the closing date to April 29, 2011. The Company agreed to provide 1,500,000 shares of stock in a non-refundable deposit in exchange for this extension, which shares will either be returned or applied to the purchase price at closing.

The Company and its subsidiaries have not been in bankruptcy, receivership, or any similar proceeding, and, to the best knowledge of management, have not defaulted on the terms of any note, loan, lease, or other indebtedness or financing arrangement requiring the issuer to make any material payments. Other than described above, the Company has not recently been a party to any material reclassification, merger, consolidation, or purchase or sale of a significant amount of assets not in the ordinary course of business.

Areas of Operation

Powder River Basin



The Powder River Basin is located in northeastern Wyoming and southeastern Montana and covers an area of approximately 25,800 square miles, of which approximately 75% is in Wyoming. Fifty percent of the Powder River Basin is believed to have the potential for coalbed methane (“CBM”) production.

Coal beds in this region intermingle at varying depths with sandstones and shale. The majority of the productive coal zones range from 150 feet to 1,850 feet below ground. The uppermost formation is the Wasatch Formation, extending from land surface to 1,000 feet deep. Most of the coal seams in the Wasatch Formation are continuous, but thin (six feet or less). The Fort Union Formation lies directly below the Wasatch Formation and can be as thick as 3,000 feet. The coal beds in Fort Union formation are usually more plentiful in the upper portion, named the Tongue River member. This member is normally 1,500 to 1,800 feet thick, of which a net total of 350 feet of coal can be found in various seams. The thickest of the individual coal seams is over 150 feet thick.

CBM production is primarily from the Fort Union rather than the overlying Wasatch. The Fort Union Formation supplies municipal water to the city of Gillette, WY and is the same formation that contains the coals that are developed for CBM. The coal beds contain and transmit more water than the sandstones. The sandstones and coal beds are both used for the production of water and the production of CBM. Total Dissolved Solids (TDS) levels in the water produced from these coal beds meet the water quality criteria for drinking water. The huge coal deposits contain enormous amounts of methane gas due to their unusual thickness as evident in the amount of coal produced from this region. The low gas content per ton and low pressure were initially seen as barriers to development. The first wells drilled and completed produced massive volumes of water but little gas. As companies altered their drilling to more shallow wells, production increased. The low drilling costs, the short completion time and the relatively good quality of water coupled with inexpensive water management i.e. surface discharge encouraged development.

Coal Bed Methane Industry

Overview. Once a nuisance and mine safety hazard, CBM has become a valuable part of our Nation's energy portfolio. CBM production has increased during the last 15 years and now accounts for about a twelfth of U.S. natural gas production. As America's natural gas demand grows substantially over the next two decades, CBM will become increasingly important for ensuring adequate and secure natural gas supplies for the United States.

CBM is simply methane found in coal seams. Most coal beds are permeated with methane, and a cubic foot of coal can contain six or seven times the volume of natural gas that exists in a cubic foot of a conventional sandstone reservoir. It is produced by non-traditional means, and although it is sold and used the same as traditional natural gas, its production is very different. Often a coal seam is saturated with water which provides a trapping mechanism to contain the methane inside the coal seams.

Within coal seams, methane is present on the surface of the solid material. Hydrostatic pressure causes the methane to adhere to the coal surface via a phenomenon termed adsorption. Whenever reservoir pressure is reduced, the methane desorbs off of coal surfaces, diffuses through the matrix material, and then flows through a system of natural fractures (cleats) and into a well for delivery to the surface. CBM is the same as the natural gas in our transmission and distribution pipelines; it is used for space heating and power generation, as a feedstock for chemical production, and in manufacturing processes.

Coal bed natural gas is either biogenic or thermogenic in origin. Biogenic methane is generated from bacteria in organic matter and is typically a dry gas. It is generally found at depths of less than 1,000 feet from the earth's surface in low-rank coals (those coals with a lower carbon content). Thermogenic methane forms when heat and pressure transform organic matter in coal into methane. This type of methane is typically a wet gas and frequently contains trace amounts of water vapor, carbon dioxide, nitrogen, and possibly hydrogen sulfide. It is generally found at greater depths, in higher-rank coals.

The contiguous United States is estimated to have CBM in-place resources of 700 trillion cubic feet (Tcf), of which 100 Tcf may be economically recoverable. The most prolific basins exist in the western United States, but eastern areas of the nation also have notable reserves of CBM. Other areas that have significant CBM potential include Alaska and the Illinois Basin.

United States and the Basin Coal Bed Natural Gas Resources. United States CBM proved reserves and production have grown nearly every year since 1989. In 2007, CBM accounted for 21.9 Tcf of the reserves in the U.S., with 1.6 Tcf being produced in 2007. CBM produced in Colorado, New Mexico, and Wyoming totaled nearly 1.3 Tcf during 2007, which represents over 80% of total CBM production in the U.S. Other notable producing areas include the Central Appalachian and Warrior basins in the eastern United States and the Uinta and Raton basins in the Rocky Mountain region. The majority of future CBM production is expected from western basins.

Estimates of amounts of methane gas in the Basin vary and are often re-calculated. There are several methods to estimate the amount of recoverable gas from a coal seam, all having varying degrees of accuracy.

Coal bed natural gas can be recovered from underground mines before, during, or after mining operations. Significant volumes of CBM also are extracted from "non-mineable" coal seams that are relatively deep or thin, of poor or inconsistent quality, or represent difficult mining conditions. Ninety percent of the country's coal resource is non-mineable but represents a vast potential source of natural gas.

Vertical and horizontal wells, including multi-laterals, are used to develop CBM resources. For the most part, the quality of a seam's cleat system (high-conductivity flow paths) will dictate the type of well completion and stimulation employed. In high-permeability settings, flow enhancement may not be required. In other situations, hydraulic fracturing and cavitation stimulations are used.

Although development of CBM resources has been quite successful, the industry continues to face many issues. These issues are varied, some highly contentious, and include access to resources, permitting, exhaustive environmental planning, litigation, produced-water management, natural gas markets and capital formation, and the need for advanced technologies.

Another important environmental issue for CBM developers stands as a positive. The release of methane into the atmosphere, either through natural seeps, ventilation during mining, or via other means, has environmental consequences. Methane is a potent greenhouse gas, with 21 times the global warming potential of carbon dioxide. In fact, coal mining accounts for about 10% of U.S. methane emissions. Therefore, recovery of CBM mitigates a large source of methane emissions and allows for economic use of the energy source.

How does CBM Compare to Conventional Natural Gas? Methane is the chief component of natural gas, and CBM can be used in very much the same way as conventional gas. Conventional gas is formed in limestone and shale formations; pressure and temperature unite to transform organic matter into hydrocarbons over time, similar to thermogenic production in deeper coals. Natural gas migrates upward until trapped by a geologic barrier or fault and remains in this reservoir until it is discovered and drilled, or released by some natural means. Conventional gas wells are typically 4,000 to 12,000 feet deep and extract gas from sandstone and shale formations. The location and extent of conventional gas typically requires exploratory drilling since the location of reservoirs is not apparent from the surface. Coal bed wells are generally considered shallow and range from 400 to 1,500 feet in the Basin but can be as deep as 5,000 feet in some basins.

Company Projects

Dry Fork. The Company began its operations in 2007 with the acquisition of the Dry Fork project in the Powder River Basin. We first acquired acreage in the Basin by securing a lease with Western Fuel Cooperative (Dry Fork Mine) for all methane within a depth of 3,000 feet of surface. We developed this project and had drilled and completed seven wells on this lease. These wells are currently in the de-watering stage. The Company proceeded to build infrastructure and gathering pipelines on the Dry Fork lease which essentially controls the access to this project by owning the only transmission line to the nearest sales point. This development makes up the Dry Fork Phase I and may ultimately be comprised of 70 newly drilled wells. Dry Fork Phase II is a continuation of Phase I and may include an additional 83 newly drilled wells.

Grams and Mills Gillette Field. In October 2010, the Company acquired a total of 57 shut-in wells in the Grams and Mills Gillette fields, with an additional 10 drilling locations permitted, and another four locations in the permitting process. Seven wells have been recompleted and re-enhanced with an additional seven more wells scheduled in the near future.

The Pennaco North and South Fairway Acquisition. On November 19, 2010 the Company secured approximately 155,000 net acres of leasehold, including 1,614 wells of which 493 wells are active and producing, from Pennaco Energy, a subsidiary of Marathon Oil (the "Marathon Assets"). This acquisition included approximately 13,600 Mcf/d net being produced from the 493 active wells. The Marathon Assets have approximate 97% Working Interest

(“WI”) with a Net Revenue Interest (“NRI”) of approximately 80%. The Company assumed operational control on December 1, 2010 and has been successful in activating several of the 1,100+ idle wells acquired with the property.

This is potentially helpful to the Company not only by increasing daily production, but in decreasing and delaying idle well bonding costs associated with the properties. These properties and wells comprise a significant opportunity and responsibility for the Company in the refurbishment and re-activation plan. The Company believes it can re-activate approximately 20-30 wells per month and place these wells into successful production, thus increasing gas production and sales. The Company believes that there are over 40,000 net acres of undeveloped acres and opportunities for future drill sites on the property as well. The Company intends to refurbish and re-activate wells while natural gas pricing is relatively low and prepare for future developments via drilling programs as natural gas prices strengthen to a level that warrants development of available acreage. The Company is active in managing its operational costs and focused on reducing these costs in the future.

Oil and Gas Data

Proved Reserves
The data in the below table represent estimates by NSAI, a leading independent third party engineering firm with extensive experience in the Powder River Basin. At this time, we believe they are more knowledgeable about the wells due to the continual analysis throughout the year for other companies operating in the region as compared to the relatively short term analysis performed internally.

The natural gas reserves are an estimation of accumulations of natural gas that cannot be measured exactly. The accuracy of any reserves estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserves may vary from the quantities of oil and natural gas that are ultimately recovered. See “Item 1A. Risk Factors.”

The following table presents our estimated net proved natural gas reserves and the present value of our estimated proved reserves at December 31, 2010 based on reserve report prepared by outside independent third party petroleum engineers. All of our proved reserves included in our reserve report are located in North American. Netherland, Sewell & Associates, Inc. (“NSAI”) prepared our reserves estimates as of December 31, 2010.

	Gas Reserves		Future Net Revenues ($)	
Category	Gross MCF	Net MCF	Total	Present Worth at 10%
Proved Developed Producing	9,389,434	6,357,905	9,136,600	8,301,500
Proved Developed Non-Producing	7,474,463	5,253,624	9,137,900	7,167,900
Proved Undeveloped	4,093,289	2,613,872	3,194,500	1,393,200
Total Proved	20,957,186	14,225,401	21,469,000	16,862,600
Probable Developed	31,041,451	15,973,270	29,558,600	22,564,200
Probable UnDeveloped	87,752,757	55,580,483	78,061,800	33,702,000
Total Probable	118,794,208	71,553,753	107,620,400	56,266,200
Possible Developed	27,490,451	6,862,488	14,471,700	10,383,500
Possible Undeveloped	95,848,508	62,726,123	80,437,500	33,829,600
Total Possible	123,338,959	69,588,611	94,909,200	44,213,100

Gas volumes are expressed in thousands of cubic feet (MCF) at standard temperature and pressure bases.

The estimates shown in this table are for proved reserves. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Future gross revenue to the HPG interest is prior to deducting state production taxes and ad valorem taxes. Future net revenue is after deductions for these taxes, future capital costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

For the purposes of this report, NSAI did not perform any field inspection of the properties, nor did NSAI examine the mechanical operation or condition of the wells and facilities. NSAI has not investigated possible environmental liability related to the properties; therefore, the estimates do not include any costs due to such possible liability. Also, the estimates do not include any salvage value for the lease and well equipment or the cost of abandoning the properties.

Gas prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the- month price for each month in the period January through December 2010. The average CIG Rocky Mountains spot price of $3.945 per MMBTU is adjusted by area for energy content and transportation fees. All prices are held constant throughout the lives of the properties. For the proved reserves, the average adjusted gas price weighted by production over the remaining lives of the properties is $3.162 per MCF.

Lease and well operating costs used in this report are based on operating expense records of HPG and the previous owners of the properties. For nonoperated properties, these costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. As requested, lease and well operating costs for the operated properties include only direct lease- and field-level costs. For all properties, headquarters general and administrative overhead expenses of HPG are not included. Lease and well operating costs are held constant throughout the lives of the properties. Capital costs are included as required for workovers, new development wells, and production equipment. The future capital costs are held constant to the date of expenditure.

NSAI has made no investigation of potential gas volume and value imbalances resulting from overdelivery or underdelivery to the HPG interest. Therefore, the estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on HPG receiving its net revenue interest share of estimated future gross gas production.

For the purposes of this report, NSAI used technical and economic data including, but not limited to, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). NSAI used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that NSAI considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and guidelines.

The data used in our estimates were obtained from HPG, previous owners of the properties, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting geoscience, performance, and work data are on file in our office. The titles to the properties have not been examined by NSAI, nor has the actual degree or type of interest owned been independently confirmed. The technical persons responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. NSAI are independent petroleum engineers, geologists, geophysicists, and petrophysicists; NSAI does not own an interest in these properties nor are they employed on a contingent basis.

The reserves estimates shown herein have been estimated by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-002699. Within NSAI, the technical person primarily responsible for auditing the estimates set forth in the NSAI audit letter incorporated herein is Diana Ball. Ms. Ball has been practicing consulting petroleum engineering at NSAI since 1997. She has an MBA with Finance concentration from University of St. Thomas, Houston, 1985; BS in Petroleum Engineering, University of Tulsa, 1980. Diana joined NSAI in 1997. She has extensive CBM experience including multiple domestic projects in the Black Warrior, San Juan, Raton, Uinta, and Powder River Basins.
The NSAI process of estimating our wells and reserves are intended to determine the net proved reserves estimate and future net revenue (discounted 10%). The process includes the following:

- The NSAI engineer performs an independent decline curve analysis on proved producing wells based on production and pressure data. This data is provided to NSAI by us as well as other companies operating in the Powder River Basin;

- The NSAI engineer may verify the production data with the public data;

- The NSAI engineer uses his or her individual interpretation of the information and knowledge of the reservoir and area to make an independent analysis of proved producing reserves;

- The NSAI technical staff will prepare independent maps and volumetric analyses on our properties and offsetting properties. They review our geologic maps, log data, core data, pertinent pressure data, test information and pertinent technical analyses, as well as data from offsetting producers;

- The NSAI engineer will estimate the hydrocarbon recovery of the remaining gas-in-place based upon his/her knowledge and experience; and

- The NSAI engineer confirms the oil and gas prices used for the SEC reserves estimate.

The reserves audit letter provided by NSAI states that "the estimates in this report have been prepared in accordance with the definitions and guidelines of the U.S. Securities and Exchange Commission (SEC) and conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities – Oil and Gas, except that per-well overhead expenses are excluded for operated properties and future income taxes are excluded for all properties."
On December 31, 2008, the SEC published final rules and interpretations updating its oil and gas reserves reporting requirements called "Modernization of Oil and Gas Reporting." Many of the revisions were 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 set of evaluation guidelines that are designed to support assessment processes throughout the resource asset lifecycle. These guidelines were prepared by the Society of Petroleum Engineers, or SPE, Oil and Gas Reserves Committee with cooperation from many industry organizations. One of the key changes to the previous SEC rules related to using a 12-month average commodity price to calculate the value of proved reserves versus the former method of using year-end prices. Other key revisions included the ability to include nontraditional resources in reserves, the use of new technology for determining reserves, the opportunity to establish proved undeveloped reserves without the requirement of an adjacent producing well and permitting disclosure of probable and possible reserves. Companies were required 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 31, 2009. Early adoption was not permitted.

Operations

General

The Company is engaged in the operation and production of 1,726 methane wells located in the Powder River Basin near Gillette, WY. The company's business strategy focuses on revenue from production and operation of owned wells, including rework or existing wells designed to increased production. The Company's ability to manage production costs and increase revenues on a per well basis provides a formula for continued operational success and distinguishes us from our competitors. We are also actively engaged in the acquisition of properties, primarily in the Powder River Basin, which contain revenue from existing production and leased but undeveloped mineral acreage.

High Plains' management of costs associated with the operation of methane wells is the company's competitive advantage. By managing our lifting costs per MCF at a lower rate than our competitors, the company is able to acquire wells that companies with higher cost structures are forced to abandon. This cost structure, when combined with the expected increases in production associated with the rework of wells and pipeline systems, creates a sustainable business model for the operation and production of High Plains' methane wells.

Natural Gas Marketing and Delivery Commitments

The spot markets for natural gas are subject to volatility as supply and demand factors fluctuate. As detailed below, we sell our production under both long-term (one year or more) or short-term (less than one year) agreements. Regardless of the term of the contract, the vast majority of our production is sold at variable or market sensitive prices.

Natural Gas Marketing. Our natural gas is transported through our own and third party gathering systems and pipelines, and we incur processing, gathering and transportation expenses to move our natural gas from the wellhead to a purchaser-specified delivery point. Our natural gas is also sold under both long-term and short term agreements at prices negotiated with third parties.

These expenses vary based on the volume and distance shipped, and the fee charged by the third-party gatherer, processor or transporter. Capacity on these gathering systems and pipeline s is occasionally limited and at times unavailable because of repairs or improvements, or as a result of priority transportation agreements with other gas shippers. While our ability to market our natural gas hasn't been delayed, if transportation space is restricted or is unavailable, our cash flow from the affected properties could be adversely affected. In certain instances, we enter into firm transportation agreements to provide for pipeline capacity to flow and sell a portion of our gas volumes.

Delivery Commitments. A portion of our production is sold under certain contractual arrangements that specify the delivery of a fixed and determinable quantity. The following table sets forth information about material long- term firm transportation contracts for pipeline capacity. These contracts were acquired as part of the acquisition of the Pennaco "North & South Fairway Assets." Under these firm transportation contracts, we are obligated to deliver minimum daily gas volumes, or pay the respective transportation fees for any deficiencies in deliveries. Although exact amounts vary, as of December 31, 2010 we were committed to deliver the following fixed quantities of our natural gas production:

Type of Arrangement	Pipeline System / Location	Deliverable Market	Gross Deliveries (MMBtu/d)	Term
Firm Transport	WIC Medicine Bow	Rocky Mountains	15,000	07/10 –11/15
Firm Transport	Kinder Morgan Trailblazer	Rocky Mountains	22,500	07/10 - 05/12
Firm Transport	Copano Fort Union	Rocky Mountains	10,000	07/10 - 11/11

Hedging Activities

We enter into hedging transactions with unaffiliated third parties for portions of our production revenues to achieve more predictable cash flows and to reduce our exposure to fluctuations in commodities prices. Typically, we intend to hedge approximately 40-60% of our natural gas production on a forward 12-24 month basis.

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies, some that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies are able to pay more for productive oil and natural gas 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, these companies have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. Our larger or integrated competitors are better able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations than we can, which could adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties.

Major Customers

We sell the majority of our gas production to pipelines. Gathering systems and interstate and intrastate pipelines are used to consummate gas sales and deliveries. Although a substantial portion of production is purchased by these pipelines, we do not believe the loss of any one or several customers would have a material adverse effect on our business as other customers or markets would be accessible to us.

Title to Properties

We have obtained title opinions on substantially all of our producing properties and believe that we utilize methods consistent with practices customary in the oil and natural gas industry and that our practices are adequately designed to enable us to acquire satisfactory title to our producing properties. Prior to completing an acquisition of producing natural gas and oil leases, we perform title reviews on the most significant leases and, depending on the materiality of the properties, we may obtain a title opinion or review previously obtained title opinions.

It is expected that prior to the commencement of any drilling operations, we will conduct thorough title examination and perform curative work for significant defects. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property.

Seasonal Nature of Business

Generally, but not always, the demand for natural gas decreases during the spring and fall months and increases during the summer and winter months. Seasonal anomalies such as mild winters or cool summers sometime lessen this fluctuation. In addition, pipelines, utilities, local distribution companies and industrial 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 natural gas operations in certain areas of the Rocky Mountain region. These seasonal anomalies can pose challenges for meeting our well drilling and recompletion objectives and can 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.

Public Policy and Government Regulation of Oil and Gas Industry

Regulation of the Oil and Gas Industry. The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities and is under constant review for amendment or expansion, frequently increasing the regulatory burden. Pursuant to public policy changes, numerous government agencies have issued extensive laws and regulations binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

Drilling and Production Regulation. Our operations are subject to various types of regulation at federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties and municipalities also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the rates of production;
- the surface use and restoration of properties upon which wells are drilled and other third parties;
- wildlife management and protection;
- emissions and discharge permitting;
- the plugging and abandoning of wells; and
- notice to, and consultation with, surface and other third parties

Our operations are also subject to conservation regulations, including the size and shape of drilling and spacing units or proration units governing the pooling of natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases, which may make it more difficult to develop oil and gas properties. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws can establish maximum rates of production from natural gas wells, and generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill.

Moreover, each state generally imposes a production or severance tax with respect to the production and sale of natural gas within its jurisdiction.

Federal, state and local laws and regulations affect our business, including those relating to protection of the environment, public health, and worker safety. Substantial liabilities, including civil and criminal penalties may result from the technical requirements of these laws and regulations. In addition, certain laws impose strict liability for environmental remediation and other costs. Changes in any of these laws and regulations could have a material adverse effect on our business. In light of the many uncertainties with respect to future laws and regulations, we cannot predict the overall effect of such laws and regulations on our future operations. Nevertheless, the trend in environmental regulation is to place more restrictions and controls on activities that may affect the environment, and future expenditures for environmental compliance or remediation may be substantially more than we expect.

Environmental Matters and Regulation

Environment. Our operations are subject to stringent federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Our operations are subject to the same environmental laws and regulations as other companies in the oil and gas exploration and production industry. These laws and regulations:

- require the acquisition of various permits before drilling commences;
- require the installation of expensive pollution control equipment;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on lands lying within environmentally sensitive areas, wilderness, wetlands and other protected areas;
- require measures to prevent pollution from former operations, such as pit closure and plugging of abandoned wells;
- impose substantial liabilities for pollution resulting from our operations;
- with respect to operations affecting federal lands or leases, require time consuming environmental analysis with uncertain outcomes; and
- exposure to litigation by environmental and other special interest groups.

These laws, rules and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost and timing of doing business and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise the environmental laws and regulations, and any changes that result in delay or more stringent and costly permitting, waste handling, disposal and clean-up requirements for the oil and gas industry could have a significant impact on our operating costs.

We believe that we substantially are in compliance with and have complied, with all applicable environmental laws and regulations. We have made and will continue to make expenditures in our efforts to comply with all environmental regulations and requirements. We consider these a normal, recurring cost of our ongoing operations and not an extraordinary cost of compliance with governmental regulations. We believe that our continued compliance with existing requirements have been accounted for and will not have a material adverse impact on our financial condition and results of operations. However, we cannot predict the passage of or quantify the potential impact of any more stringent future laws and regulations at this time. For the year ended December 31, 2010, we did not incur any material capital expenditures for remediation or retrofit of pollution control equipment at any of our facilities.

The environmental laws and regulations that could have a material impact on the oil and natural gas exploration and production industry and our business are as follows:

Natural Gas Sales and Transportation. Historically, federal legislation and regulatory controls have affected the price of the natural gas we produce and the manner in which we market our production. The Federal Energy Regulatory Commission, or FERC, has jurisdiction over the transportation and sale or resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Since 1978, various federal laws have been enacted that have resulted in the complete removal of all price and non-price controls for sales of domestic natural gas sold in "first sales," which include all of our sales of our own production.

FERC also regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Commencing in 1985, FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC's initiatives have led to the development of a competitive, unregulated, open access market for gas purchases and sales that permits all purchasers of gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, we cannot guarantee that the less stringent regulatory approach recently pursued by FERC and Congress will continue indefinitely into the future, nor can we determine what effect, if any, future regulatory changes might have on our natural gas-related activities.

Under FERC's current regulatory regime, transmission services must be provided on an open-access, non-discriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. Gathering services, which occurs upstream of jurisdictional transmission services, is regulated by state agencies. Although its policy is still in flux, FERC recently has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of transporting gas to point-of-sale locations.

National Environmental Policy Act. Natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the Departments of Interior and Agriculture, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will have an environmental assessment prepared that assesses the potential direct, indirect and cumulative impacts of a proposed project. This process has the potential to delay the development of oil and natural gas projects. Authorizations under NEPA also are subject to protest, appeal or litigation, which can delay or halt projects.

Water Discharges. The Federal Water Pollution Control Act, also known as the Clean Water Act, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other gas wastes, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. We maintain all required discharge permits necessary to conduct our operations, and we believe we are in substantial compliance with the terms thereof. Obtaining permits has the potential to delay the development of natural gas projects. These same regulatory programs also limit the total volume of water that can be discharged, hence limiting the rate of development.

Air Emissions. The Federal Clean Air Act, and associated state laws and regulations, regulate emissions of various air pollutants through the issuance of permits and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. The EPA has recently deemed carbon dioxide ("CO_2") to be a public danger which presumably will lead to regulation in a manner similar to other pollutants. The EPA now requires reporting of greenhouse gases, CO_2 and methane, from operations. We believe that we are in compliance with all air emissions regulations and that we hold all necessary and valid construction and operating permits for our operations. Obtaining permits has the potential to delay the development of natural gas projects.

Climate Change

In response to findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment because emissions of such gases are contributing to warming of the earth's atmosphere and other climatic changes, the EPA had adopted regulations under existing provisions of the federal Clean Air Act that would require a reduction in emissions of GHGs, from motor vehicles and, also, could trigger permit review for GHG emissions from certain stationary sources, commencing when the motor vehicle standards took effect on January 2, 2011.

The EPA published its final rule to address the permitting of GHG emissions from stationary sources under the PSD and Title V permitting programs. This rule "tailors" these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. It is widely expected that facilities required to obtain PSD permits for their GHG emissions also will be required to reduce those emissions according to "best available control technology" standards for GHG that have yet to be developed. With regards to the monitoring and reporting of GHGs, on November 30, 2010, the EPA published a final rule expanding its existing GHG emissions reporting rule published in October 2009 to include onshore oil and natural gas production activities, which may include certain of our operations. In addition, both houses of Congress have actively considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. The adoption and implementation of any legislation or regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

Endangered Species, Wetlands and Damages to Natural Resources

Various state and federal statutes prohibit certain actions that adversely affect endangered or threatened species and their habitat, migratory birds, wetlands, and natural resources. These statutes include the Endangered Species Act, the Migratory Bird Treaty Act, the Clean Water Act and CERCLA. Were taking of or harm to species or damages to wetlands, habitat, or natural resources occur or may occur, government entities or at times private parties may act to prevent oil and gas exploration or production or seek damages to species, habitat, or natural resources resulting from filling or construction or releases of oil, wastes, hazardous substances or other regulated materials.

OSHA and Other Laws and Regulations

We are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. The OSHA hazard communication standard, the Emergency Planning and Community Right to Know Act and similar state statutes require that we organize and/or disclose information about hazardous materials stored, used or produced in our operations.

Private Lawsuits

In addition to claims arising under state and federal statutes, where a release or spill of hazardous substances, oil and gas or oil and gas wastes have occurred, private parties or landowners may bring lawsuits against the Company and could possibly delay the development of natural gas projects.

Offices

As of April 15, 2011, the Company is finishing negotiations to lease office space in Gillette, Wyoming at 3601 Southern Drive, Gillette, Wyoming 82718, where we currently occupy office space. After the Marathon transaction was completed, we remained in the office space on a month to month lease while terms for a new lease are being negotiated. We believe that our facilities are adequate for our current operations.

Intellectual Property

The Company gained access to the ARID equipment and its proprietary usage through its Agreement with Big Cat Energy. The tool and its technology allows the Company to inject water from the production formation into alternate formations thus dewatering the production zone and not incurring undesirable excess water at the surface and related pumping costs. This allows the Company to access properties which may have been previously undevelopable due to water drainage issues or undevelopable due to high pumping and disposal costs. The Company views this technology as an important economic and strategic advantage. The Company does not otherwise hold patents on any of its processes.

Employees

As of March 31, 2011, we had a total of four officers and we had 53 full time equivalent employees located in Gillette, WY. We also contract for the services of independent consultants involved in land, regulatory, accounting, financial and other disciplines as needed. None of our employees are represented by labor unions or covered by any collective bargaining agreement. We believe that our relations with our employees are good.

Website and Available Information

We make available copies of our Annual Report, Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, amendments to those, and other reports filed with the Securities and Exchange Commission ("SEC") under “Investor Relations” on our website, *www.highplainsgas.com*, as soon as reasonably practicable after they are filed. Our website's content is not intended to be incorporated by reference into this report or any other report we file with the SEC. You may request a paper copy of materials we file with the SEC by calling us at (307) 686-5030 or sending a request by mail to our corporate secretary at our principal office at 3601 Southern Drive, Gillette, WY 82718. You may read and copy materials we file with the SEC on the SEC's website at *www.sec.gov*, or at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. You may obtain information on the operation of the Public Reference Room by calling (800) 732-0330.

Fiscal Year

On February 14, 2011, concurrent with the reverse merger, we changed our fiscal year end to December 31 from what had previously been March 31. Accordingly, our first, second, third and fourth quarters now end March 31, June 30, September 30 and December 31, respectively.

Glossary of Oil and Natural Gas Terms

The following are abbreviations and definitions of certain terms used in this document, which are commonly used in the oil and gas industry:

Basin-centered gas. A regional, abnormally pressured, gas-saturated accumulation in low-permeability reservoirs lacking a down-dip water contact.

Bcf. Billion cubic feet of natural gas.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Btu or British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Coalbed methane or CBM. Natural gas formed as a byproduct of the coal formation process, which is trapped in coal seams and can be produced into a pipeline.

Completion. Installation of permanent equipment for production of oil and gas, or, in the case of a dry well, to reporting to the appropriate authority that the well has been abandoned.

Desorb. A physical process whereby gas molecules are liberated from a host rock, such as a shale or coal reservoir, when the formation pressure is reduced.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Development well. A well drilled within the proved area of a natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole or Dry well. An exploratory, development, or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

Environmental Assessment or EA. A study that can be required pursuant to federal law prior to drilling a well.

Environmental Impact Statement or EIS. A more detailed study that can be required pursuant to federal law of the potential direct, indirect and cumulative impacts of a project that may be made available for public review and comment.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir.

Field. An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Identified drilling locations. Total gross locations specifically identified and scheduled by management as an estimation of our multi-year drilling activities on existing acreage. Our actual drilling activities may change depending on the availability of capital, regulatory approvals, seasonal restrictions, natural gas and oil prices, costs, drilling results and other factors.

Mcf. Thousand cubic feet of natural gas.

Mcf/d. Mcf per day.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

MMcf/d. MMcf per day.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.

Net revenue interest. An owner's interest in the revenues of a well after deducting proceeds allocated to royalty and overriding interests.

Plugging and abandonment. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.

Productive well. An exploratory, development, or extension well that is not a dry well.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved developed reserves or PDP. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved reserves. The quantities of oil, natural gas and natural gas liquids, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from know reservoirs, and under existing economic conditions, operating methods, and government regulations.

Proved undeveloped reserves or PUD. Reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Recompletion. The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

Record of Decision or ROD. A document that authorizes or denies the activity analyzed by an Environmental Impact Statement and provides the basis for this decision.

Resource Management Plan or RMP. A document that describes the Bureau of Land Management's intended uses of lands that are under its jurisdiction

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.

Stratigraphic play. An oil or natural gas formation contained within an area created by permeability and porosity changes characteristic of the alternating rock layer that result from the sedimentation process.

Structural play. An accumulation of oil and gas in rock strata that has been folded or faulted.
Tcf. Trillion cubic feet (of gas)

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether such acreage contains proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.

Item 1A. Risk Factors

Our business involves a high degree of risk. If any of the following risks, or any risk described elsewhere in this Form 10-K, actually occurs, our business, financial condition or results of operations could suffer. The risks described below are not the only ones facing us. Additional risks not presently known to us or that we currently consider immaterial also may adversely affect our Company.

Risk Factors Concerning the Company's Business and Operations

Natural gas prices are volatile and a decline in natural gas prices can significantly affect our financial results and impede our growth.

Historically natural gas prices have been volatile and will likely continue to be volatile in the future. U.S. natural gas prices in particular are significantly influenced by weather and many other factors. Any significant or extended decline in commodity prices would impact the Company's future financial condition, revenue, operating result, cash flow, return on invested capital, and rate of growth. The Company cannot predict the future price of natural gas because of factors beyond its control, including but not limited to:

- changes in domestic and foreign supply of natural gas;
- changes in local, regional, national and global demand for natural gas;
- regional price differences resulting from available pipeline transportation capacity or local demand;
- the level of imports of, and the price of, foreign natural gas;
- domestic and global economic conditions;
- domestic political developments;
- weather conditions;
- domestic and foreign government regulations and taxes;
- technological advances affecting energy consumption and energy supply;
- political instability or armed conflict in natural gas producing regions;
- conservation efforts;
- the price, availability and acceptance of other fuel sources and alternative fuels;
- storage levels of natural gas;
- the quality of gas produced; and
- the development and supply of more competitive natural gas sources.

The Company may not be able to economically find and develop new economic reserves.

The Company's profitability depends not only on prevailing prices for natural gas, but also its ability to find, develop and acquire gas reserves that are economically recoverable. Producing natural gas reservoirs are generally characterized by declining production rates that vary depending on reservoir characteristics. Because of the high-rate production decline profile of several of the Company's producing areas, substantial capital expenditures are required to find, develop and acquire gas reserves to replace those depleted by production.

Gas reserve estimates are imprecise and subject to revision.

The Company proved natural gas reserve estimates are prepared annually by independent reservoir-engineering consultants. Although the Company utilizes reputable and reliable experts, gas reserve estimates are subject to numerous uncertainties inherent in estimating quantities of proved reserves, projecting future rates of production and timing of development expenditures. The accuracy of these estimates depends on the quality of available data and on engineering and geological interpretation and judgment. Reserve estimates are imprecise and will change as additional information becomes available. Estimates of economically recoverable reserves and future net cash flows prepared by different engineers, or by the same engineers at different times, may vary significantly. Results of subsequent drilling, testing and production may cause either upward or downward revisions of previous estimates. In addition, the estimation process also involves economic assumptions relating to commodity prices, production costs, severance and other taxes, capital expenditures and remediation costs. Actual results most likely will vary from the estimates. Any significant variance from these assumptions could affect the recoverable quantities of reserves attributable to any particular properties, the classifications of reserves, the estimated future net cash flows from proved reserves and the present value of those reserves.

Shortages of oilfield equipment, services and qualified personnel could impact results of operations.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and gas industry can fluctuate significantly, often in correlation with natural gas and oil prices, causing periodic shortages. There have also been regional shortages of drilling rigs and other equipment, as demand for specialized rigs and equipment has increased along with the number of wells being drilled. These factors also cause increases in costs for equipment, services and personnel. These cost increases could impact profit margin, cash flow and operating results or restrict the ability to drill wells and conduct operations, especially during periods of lower natural gas and oil prices.

Operations involve numerous risks that might result in accidents and other operating risks and costs.

Drilling is a high-risk activity. Operating risks include: fire, explosions and blow-outs; unexpected drilling conditions such as abnormally pressured formations; abandonment costs; pipe, cement or casing failures; environmental accidents such as oil spills, natural gas leaks, ruptures or discharges of toxic gases, brine or well fluids (including groundwater contamination). The Company could incur substantial losses as a result of injury or loss of life; pollution or other environmental damage; damage to or destruction of property and equipment; regulatory investigation; fines or curtailment of operations; or attorney's fees and other expenses incurred in the prosecution or defense of litigation.

There are also inherent operating risks and hazards in the Company's gas and oil production, gas gathering, processing, transportation and distribution operations that could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution, impairment of operations and substantial losses. The location of pipelines near populated areas, including residential areas, commercial business centers and industrial sites could increase the level of damages resulting from these risks. Certain segments of the Company's pipelines run through such areas. In spite of the Company's precautions, an event could cause considerable harm to people or property, and could have a material adverse effect on the financial position and results of operations, particularly if the event is not fully covered by insurance.

As is customary in the natural gas industry, the Company maintains insurance against some, but not all, of these potential risks and losses. The Company cannot assure that insurance will continue to be available on acceptable terms or will be adequate to cover these losses or liabilities. Losses and liabilities arising from uninsured or underinsured events could have a material adverse effect on the Company's financial condition and operations.

Disruption of, capacity constraints in, or proximity to pipeline systems could impact results of operation.

The Company transports gas to market by utilizing pipelines principally owned by third parties ,and to a limited degree, the Company. If pipelines do not exist near producing wells, if pipeline capacity is limited or if pipeline capacity is unexpectedly disrupted, gas sales could be reduced or shut in, reducing profitability.

The Company is subject to complex regulations on many levels.

The Company is subject to federal, state and local environmental, health and safety laws and regulations. Environmental laws and regulations are complex, change frequently and tend to become more onerous over time. In addition to the costs of compliance, substantial costs may be incurred to take corrective actions at both owned and previously-owned facilities. Accidental spills and leaks requiring cleanup may occur in the ordinary course of business. As standards change, the Company may incur significant costs in cases where past operations followed practices that were considered acceptable at the time but now require remedial work to meet current standards. Failure to comply with these laws and regulations may result in fines, significant costs for remedial activities, or injunctions.

The Company must comply with numerous and complex regulations federal and state regulations governing activities on federal and state lands, notably the National Environmental Policy Act, the Endangered Species Act, the Clean Air Act, and the National Historic Preservation Act and similar state laws. The United States Fish and Wildlife Service may designate critical habitat areas for certain listed threatened or endangered species. A critical habitat designation could result in further material restrictions to federal land use and private land use and could delay or prohibit land access or development. The listing of certain species, such as the sage grouse, as threatened and endangered, could have a material impact on the Company's operations in areas where such species are found. The Clean Water Act and similar state laws regulate discharges of storm water, wastewater, oil, and other pollutants to surface water bodies, such as lakes, rivers, wetlands, and streams. Failure to obtain permits for such discharges could result in civil and criminal penalties, orders to cease such discharges, and other costs and damages. These laws also require the preparation and implementation of Spill Prevention, Control, and Countermeasure Plans in connection with on-site storage of significant quantities of oil.

Federal and state agencies frequently impose conditions on the Company's activities. These restrictions have become more stringent over time and can limit or prevent exploration and production on the Company's leaseholds. Certain environmental groups oppose drilling on some federal and state leases. These groups sometimes sue federal and state agencies for alleged procedural violations in an attempt to stop, limit or delay natural gas development on public lands.

Regulatory authorities, including but not limited to the Securities and Exchange Commission, exercise considerable discretion in the timing and scope of permit issuance and other needed regulatory approvals. Requirements imposed by these authorities may be costly and time consuming and may result in delays in the commencement or continuation of the Company's funding and exploration and production and midstream field services operations. Further, the public may comment on and otherwise engage in the permitting process, including through intervention in the courts. Accordingly, needed permits may not be issued, or if issued, may not be issued in a timely fashion, or may involve requirements that restrict the Company's ability to conduct its operations or to do so profitably.

The Company may be exposed to certain regulatory and financial risks related to climate change.

Federal and state courts and administrative agencies are considering the scope and scale of climate-change regulation under various laws pertaining to the environment, energy use and development, and greenhouse gas emissions. The Company's ability to access and develop new natural gas reserves may be restricted by climate-change regulation. There are bills pending in Congress that would regulate greenhouse gas emissions through a cap-and-trade system under which emitters would be required to buy allowances for offsets of emissions of greenhouse gases. In addition, several of the states in which the Company operates or may operate are considering various greenhouse gas registration and reduction programs. Carbon dioxide regulation could increase the price of natural gas, restrict access to or the use of natural gas, and/or reduce natural gas demand. Federal, state and local governments may also pass laws mandating the use of alternative energy sources, such as wind power and solar energy, which may reduce demand for natural gas. While future climate-change regulation is likely, it is too early to predict how this regulation will affect the Company's business, operations or financial results. It is uncertain whether the Company's operations and properties are exposed to possible physical risks, such as severe weather patterns, due to climate change as a result of man-made greenhouse gases. However, management does not believe such physical risks are reasonably likely to have a material effect on the company's financial condition or results of operations.

The Company may be unable to properly correct problems with "sour gas" that the Company encounters in the Company's wells.

Western Gas Resources ("WGR") previously owned a portion the Dry Fork lease. Upon drilling, WGR discovered a trace amount of hydrogen sulfide (H2S). Methane containing H2S is considered sour, and without treatment, is unmarketable. The Company owns certain treatment capability which the Company believes is sufficient to treat the gas produced by Dry Fork. The Company plans to expand the use of their gas treatment technology into additional production opportunities and leases with predictable sour gas. Nevertheless, the Company may not be able to properly treat this sour gas from the Dry Fork lease or any other, which would negatively impact the Company profitability and future plans for this area.

The recent U.S. and global economic recession could have a material adverse effect on the Company's business and operations.

Any or all of the following may occur as a result if the recent crisis in the global financial and securities markets returns:

- The Company may be unable to obtain additional debt or equity financing, which would require the Company to limit the Company's capital expenditures and other spending. This would lead to lower growth in the Company's production and reserves than if the Company were able to spend more than the Company's cash flow. Financing costs may significantly increase as lenders may be reluctant to lend without receiving higher fees and spreads; and

- The economic slowdown has led and could continue to lead to lower demand for oil and natural gas by individuals and industries, which in turn has may result in lower prices for the oil and natural gas sold by the Company, lower revenues and possibly losses.

The Company's identified drilling location inventories are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

The Company's management has specifically identified and scheduled drilling locations as an estimation of the Company's future multi-year drilling activities on the Company's existing acreage. These identified drilling locations represent a significant part of the Company's growth strategy. The Company's ability to drill and develop these locations depends on a number of uncertainties, including the availability of capital, seasonal conditions, regulatory approvals, natural gas and oil prices, costs and drilling results. Because of these uncertainties, the Company does not know if the numerous potential drilling locations the Company has identified will ever be drilled or if the Company will be able to produce natural gas or oil from these or any other potential drilling locations. As such, the Company's actual drilling activities may materially differ from those presently identified, which could adversely affect the Company's business.

All of the Company's producing properties are located in the Basin, making the Company vulnerable to risks associated with operating in one major geographic area.

The Company's operations have been focused on the Basin, which means the Company's current producing properties and new drilling opportunities are geographically concentrated in that area. Because the Company's operations are not as diversified geographically as many of the Company's competitors, the success of the Company's operations and the Company's profitability may be disproportionately exposed to the effect of any regional events, including fluctuations in prices of natural gas and oil produced from the wells in the region, natural disasters, restrictive governmental regulations, transportation capacity constraints, weather, curtailment of production or interruption of transportation, and any resulting delays or interruptions of production from existing or planned new wells.

Seasonal weather conditions and lease stipulations adversely affect the Company's ability to conduct drilling activities in some of the areas where the Company operates.

Oil and natural gas operations in the Basin are adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife. In certain areas on federal lands, drilling and other oil and natural gas activities can only be conducted during limited times of the year. This limits the Company's ability to operate in those areas and can intensify competition during those times for drilling rigs, oil field equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay the Company's operations and materially increase the Company's operating and capital costs.

Certain of our leases in the Powder River Basin are in areas that may have been partially depleted or drained by offset wells or impacted by nearby coal mining activities.

In the Powder River Basin, nearly all of our operations are in coalbed methane plays, and our key project areas are located in areas that have been the most active drilling areas in the Rocky Mountain region. As a result, many of our leases are in areas that may have already been partially depleted or drained by earlier offset drilling. This may inhibit our ability to find economically recoverable quantities of natural gas in these areas.

Properties that the Company buys may not produce as projected and the Company may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against them.

One of the Company's growth strategies is to capitalize on opportunistic acquisitions of oil and natural gas reserves. However, the Company's reviews of acquired properties are inherently incomplete, because it generally is not feasible to review in depth every individual property involved in each acquisition. Ordinarily, the Company will focus our review efforts on the higher value properties and will sample the remaining properties for reserve potential. However, even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the Company often assumes certain environmental and other risks and liabilities in connection with acquired properties.

Competition in the natural gas industry is intense, which may adversely affect the Company's ability to succeed.

The natural gas industry is intensely competitive, and the Company competes with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than the Company's financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. The Company's larger competitors may be able to absorb the burden of present and future federal, state, local and other laws and regulations more easily than the Company can, which would adversely affect the Company's competitive position. The Company's ability to acquire additional properties and to discover reserves in the future will be dependent upon the Company's ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because the Company has fewer financial and human resources than many companies in the Company's industry, the Company may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties.

Possible additional regulation related to global warming and climate change could have an adverse effect on the Company's operations and demand for oil and gas.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere. In response to such studies, the U.S. Congress is actively considering legislation to reduce emissions of greenhouse gases. In addition, several states have already taken legal measures to reduce emissions of greenhouse gases. As a result of the U.S. Supreme Court's decision on April 2, 2007 in Massachusetts, et al. v. EPA, the EPA also may be required to regulate greenhouse gas emissions from mobile sources (e.g., cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The EPA has initiated rulemaking pertaining to greenhouse gases. Other nations have already agreed to regulate emissions of greenhouse gases, pursuant to the United Nations Framework Convention on Climate Change, also known as the "Kyoto Protocol," an international treaty pursuant to which participating countries (not including the United States) have agreed to reduce their emissions of greenhouse gases to below 1990 levels by 2012. Passage of state or federal climate control legislation or other regulatory initiatives or the adoption of regulations by the EPA and analogous state agencies that restrict emissions of greenhouse gases in areas in which the Company conducts business could have an adverse effect on the Company's operations and demand for oil and gas.

Hedging production may result in losses or a reduction of profits.

From time to time, the Company may enter into hedging arrangements on a portion of its natural gas and oil production to reduce its exposure to declines in the prices of natural gas and oil. The value of these arrangements can be volatile and can materially affect the Company's future reported financial results. Hedging arrangements also expose the Company to risk of significant financial loss in some circumstances including the following:

- There is a change in the expected differential between the underlying price in the hedging agreement and actual prices received;

- Production is less than expected;

- Payments owed under derivative hedging contracts typically come due prior to receipt of the hedged months production revenues; and

- The other party to the hedging contract defaults on its contract obligations. In addition, these hedging arrangements can limit the benefit the Company would receive from increases in the prices for natural gas. Furthermore, if the Company chooses not to engage in hedging arrangements in the future, it may be more adversely by changes in natural gas than its competitors who engage in hedging arrangements.

Risk Factors Concerning Investment in the Company:

There is only a limited public market for shares of the Company's common stock, and if an active market does not develop, investors may have difficulty selling their shares and be subject to price volatility.

There is a limited public market for shares of the Company's common stock. The Company cannot predict the extent to which investor interest will lead to the development of an active trading market or how liquid that trading market might become. If a trading market does not develop or is not sustained, it may be difficult for investors to sell shares of the Company's common stock at a price that is attractive. As a result, an investment in the Company's common stock may be illiquid and investors may not be able to liquidate their investment readily or at all when desired. In addition, the limited volume may cause volatility in the market price of the Company's common stock.

As a result of our reverse merger, High Plains Gas, LLC became a subsidiary of a company that is subject to the reporting requirements of federal securities laws, which is expensive and diverts resources from other projects, thus impairing our ability to grow.

As a result of the reverse merger, High Plains Gas, LLC became a subsidiary of a public reporting company (High Plains Gas, Inc) and, accordingly, is subject to the information and reporting requirements of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). The costs of preparing and filing annual and quarterly reports, proxy statements and other information with the SEC and furnishing audited reports to stockholders will cause our expenses to be higher than they would have been if we had remained privately held and did not consummate the reverse merger.

It may be time consuming, difficult and costly for us to develop and implement the internal controls and reporting procedures required by the Sarbanes-Oxley Act. We may need to hire additional financial reporting, internal controls and other finance personnel in order to develop and implement appropriate internal controls and reporting procedures. If we are unable to comply with the internal controls requirements of the Sarbaines-Oxley Act, then we may not be able to obtain the independent registered public accountant certifications required by such Act, which may preclude us from keeping our filings with the SEC current. Non-current reporting companies are subject to various restrictions and penalties.

Management's Evaluation of Disclosure Controls and Controls over Financial Reporting have disclosed a Material Weakness in our Internal Controls

As a result of their annual assessment, management has determined there are material weaknesses in our internal controls in that we have not established an audit committee and that our accounting functions lack segregation of duties and knowledge of complex accounting matters. There is a risk of material misstatement to our financial statements or that we are unable to remediate these material weaknesses.

Public company compliance may make it more difficult for us to attract and retain officers and directors

The Sarbanes-Oxley Act and new rules subsequently implemented by the SEC have required changes in corporate governance practices of public companies. As a public company, we expect these new rules and regulations to increase our compliance costs in 2011 and beyond and to make certain activities more time consuming and costly. As a public company we also expect that these new rules and regulations may make it more difficult and expensive for us to obtain director and officer liability insurance in the future or we may be required to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. As a result, it may be more difficult for us to attract and retain qualified persons to serve on our board of directors or as executive officers.

Because we became public by means of a reverse merger, we may not be able to attract the attention of major brokerage firms.

There are risks associated with High Plains Gas, LLC becoming public through a "reverse merger." Securities analysts of major brokerage firms may not proved coverage of us since there is no incentive to brokerage firms to recommend the purchase of our common stock. No assurance can be given that brokerage firms will, in the future, want to conduct any secondary offerings on behalf of our post-reverse merger company.

The Company's common stock may be deemed to be "Penny Stock," which may make it more difficult for investors to sell their shares due to suitability requirements.

The sale price of the Company's common stock has been reported to date below $5.00 per share. As such, the Company's common stock may be subject to provisions of Section 15(g) and Rule 15g-9 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), commonly referred to as the "penny stock rule." The SEC generally defines "penny stock" to be any equity security that has a market price less than $5.00 per share, subject to exceptions with which we may or may not comply.

Broker/dealers dealing in penny stocks are required to provide potential investors with a document disclosing the risks of penny stocks. Moreover, broker/dealers are required to determine whether an investment in a penny stock is a suitable investment for a prospective investor. These requirements may reduce the potential market for the Company's common stock by reducing the number of potential investors, and may make it more difficult for investors in the Company's common stock to sell shares to third parties or to otherwise dispose of them. This could cause the stock price to decline.

Future sales by the Company's stockholders may adversely affect the Company's stock price and the Company's ability to raise funds in new stock offerings.

Sales of the Company's common stock in the public market could lower the market price of the Company's common stock. Sales may also make it more difficult for the Company to sell equity securities or equity-related securities in the future at a time and price that the Company's management deems acceptable or at all.

The Company's board of directors may authorize the issuance of additional shares that may cause dilution.

The Company's articles of incorporation permit the Company's board of directors, without shareholder approval, to authorize the issuance of additional common stock in connection with future equity offerings, acquisitions of securities or other assets of companies. The shareholders and directors of Company in fact have agreed to amend the Company's articles of incorporation to provide for a total of 350,000,000 shares of authorized common stock.

The issuance of additional shares of the Company's common stock could be dilutive to shareholders if they do not invest in future offerings. Moreover, to the extent that the Company issues options or warrants to purchase the Company's common stock in the future and those options or warrants are exercised or the Company issues restricted stock, shareholders may experience further dilution. Holders of shares of the Company's common stock have no preemptive rights that entitle them to purchase their pro rata share of any offering of shares of any class or series and investors in this offering may not be permitted to invest in future issuances of the Company's common stock.

The Company has authorized but unissued preferred stock, which could affect rights of holders of the Company's common stock.

The Company's articles of incorporation authorize the issuance of preferred stock with designations, rights and preferences determined from time to time by its board of directors. Accordingly, the Company's board of directors is empowered, without shareholder approval, to issue preferred stock with dividends, liquidation, conversion, voting or other rights that could adversely affect the voting power or other rights of the holders of the Company's common stock. In addition, the preferred stock could be issued as a method of discouraging a takeover attempt.

The Company does not expect to pay dividends on the Company's common stock.

The Company does not expect to pay any cash dividends with respect to the Company's common stock in the foreseeable future. The Company intends to retain any earnings for use in the Company's business.

Risks Related to our Notes, Convertible Notes and Credit Facility

We may not be able to generate enough cash flow to meet our debt obligations, including our obligations and commitments under our notes and our revolving credit facility.

We expect our earnings and cash flow to vary significantly from year to year due to the cyclical nature of our industry. As a result, the amount of debt that we can manage in some periods may not be appropriate for us in other periods. In addition, our future cash flow may be insufficient to meet our debt obligations and commitments. Any insufficiency could negatively impact our business. A range of economic, competitive, business, and industry factors will affect our future financial performance, and, as a result, our ability to generate cash flow from operations and to repay our debt, including the notes. Many of these factors, such as oil and gas prices, economic and financial conditions in our industry and the global economy or competitive initiatives of our competitors, are beyond our control.

As of December 31, 2010, the total outstanding principal amount of our long term indebtedness was approximately $6 million, and we had approximately $69 million in additional borrowing capacity under our Credit Facility, which, if borrowed, would be secured debt effectively senior to the Notes and Convertible Notes to the extent of the value of the collateral securing that indebtedness. The borrowing base is dependent on our proved reserves and hedge positions.

If we do not generate enough cash flow from operations to satisfy our debt obligations, we may have to undertake alternative financing plans, such as:

- refinancing or restructuring our debt;
- selling assets;
- reducing or delaying capital investments; or
- seeking to raise additional capital.

However, any alternative financing plans that we undertake, if necessary, may not allow us to meet our debt obligations. Our inability to generate sufficient cash flow to satisfy our debt obligations, including our obligations under the notes, or to obtain alternative financing, could materially and adversely affect our business, financial condition, results of operations and prospects.

Our debt could have important consequences. For example, it could:

- increase our vulnerability to general adverse economic and industry conditions;
- limit our ability to fund future capital expenditures and working capital to engage in future acquisitions or development activities, or to otherwise realize the value of our assets and opportunities fully because of the need to dedicate a substantial portion of our cash flow from operations to payments of interest and principal on our debt or to comply with any restrictive terms of our debt;

- limit or flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- impair our ability to obtain additional financing in the future; and
- place us at a competitive disadvantage compared to our competitors that have less debt.

Restrictions in our existing and future debt agreements could limit our growth and our ability to respond to changing conditions.

Our Credit Facility contains a number of significant covenants in addition to covenants restricting the incurrence of additional debt. Our Credit Facility requires us, among other things, to maintain certain financial ratios and limit our debt. These restrictions also limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under the indenture governing the notes and our Credit Facility impose on us.

A breach of any covenant in our Credit Facility or the agreements and indentures governing our other indebtedness would result in a default under that agreement or indenture after any applicable grace periods. A default, if not waived, could result in acceleration of the debt outstanding under the agreement and in a default with respect to, and an acceleration of, the debt outstanding under other debt agreements. The accelerated debt would become immediately due and payable. Our financial statements report that we are not in compliance with the restrictive covenants and, while the lender has not called the note, the credit facility gives them the ability to do so.

Other Risks

The Company relies on key executive officers and board members and their knowledge of the Company's business and technical expertise would be difficult to replace.

The Company is dependent on the Company's Board, executive officers and management team. The Company does not have "key person" life insurance policies for any of the Company's officers. The loss of the technical knowledge and management and industry expertise of any of the Company's key personnel could result in delays in product development, loss of customers and sales and diversion of management resources, which could adversely affect the Company's operating results.

If the Company is unable to hire additional qualified personnel, the Company's business may be unable to grow.

The Company will need to hire significant numbers of additional qualified personnel to operate the Company's operations. The Company's success will depend to a significant degree on the quality and integrity of the Company's work force. The Company competes for qualified individuals with numerous companies, and the Company cannot be certain that the Company's search for adequate numbers of qualified personnel will be successful.

The Company's future capital needs are uncertain.

The Company expects to incur substantial expenses for development, exploration, testing, marketing and administrative overhead and the Company believes the expansion of the Company's operations will require substantial additional capital. The combined effect of the foregoing may prevent the Company from achieving profitability for an extended period of time. If revenues do not increase as rapidly as anticipated, or if exploration, drilling, and testing and marketing require more funding than presently anticipated, the Company may be required to seek additional financing.

The Company will try to use the Company's stock to finance acquisitions.

As a key component of the Company's growth strategy, the Company intends to acquire additional leaseholds, facilities and other assets. The Company utilized stock as a finance vehicle for the acquisition of both the Marathon Assets and the Huber Assets. When possible, the Company may try to use the Company's stock as an acquisition currency in order to conserve the Company's available cash resources for operational needs. Future acquisitions may give rise to substantial charges for the impairment of goodwill and other intangible assets that would materially and adversely affect the Company's reported operating results.

Any future acquisitions will involve numerous business and financial risks, including:

- Difficulties in integrating new operations, technologies, products and staff;
- Diversion of management attention from other business concerns; and
- Cost and availability of acquisition financing.

The Company will need to be able to successfully integrate any businesses the Company may acquire in the future, and the failure to do so could have a material adverse effect on the Company's business, results of operations and financial condition.

Acquisitions by the Company may have undisclosed liabilities and the Company may be unable to integrate these businesses successfully.

In connection with any acquisition made by the Company (including without limitation the Marathon Acquisition described elsewhere in this report), there may be liabilities that the Company fails to discover or is unable to discover, including liabilities arising from non-compliance with environmental laws by prior owners and for which the Company, as successor owner, may be responsible. These liabilities could have an adverse impact on the Company's financial condition, results of operations or liquidity. The Company often attempts to minimize the Company's exposure to such liabilities by acquiring only specified assets, by obtaining indemnification from each seller of the acquired companies or by deferring payment of a portion of the purchase price as security for the indemnification. However, the Company cannot assure you that the Company will be successful in obtaining such indemnifications or that they will be enforceable, collectible or sufficient in amount, scope or duration to fully offset any undisclosed liabilities arising from the Company's acquisitions. Similarly, the Company incurs capitalized costs associated with acquisitions, which if never consummated would result in a charge to earnings.

Further, the Company cannot assure you that the Company will be able to successfully integrate any acquisitions that the Company pursues or that such acquisitions will perform as planned or prove to be beneficial to the Company's operations and cash flow. Acquisitions involve numerous risks, including difficulties in the assimilation of the acquired businesses, the diversion of the Company's management's attention from other business concerns and potential adverse effects on existing business relationships with current customers. The consolidation of the Company's operations with the operations of acquired companies, including the consolidation of systems, procedures, personnel and facilities, the relocation of staff, and the achievement of anticipated cost savings, economies of scale and other business efficiencies, presents significant challenges to the Company's management, particularly if several acquisitions occur at the same time. The Company's failure to successfully integrate businesses the Company acquires could have an adverse effect on the Company's liquidity, financial condition and results of operations.

The Company may incur more taxes and certain of the Company's projects may become uneconomic if certain federal income tax deductions currently available with respect to oil and gas exploration and development are eliminated as a result of future legislation.

There are various proposals to eliminate certain key U.S. federal income tax preferences currently available to oil and gas exploration and production companies. These changes include (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain U.S. production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures.

It is unclear whether any of the foregoing changes will actually be enacted or how soon any such changes could become effective. The passage of any legislation as a result of the budget proposal or any other similar change in U.S. federal income tax law could eliminate certain tax deductions that are currently available with respect to oil and gas exploration and development. Any such change could negatively impact the Company's financial condition and results of operations by increasing the costs the Company incurs which would in turn make it uneconomic to drill some prospects if commodity prices are not sufficiently high, resulting in lower revenues and decreases in production and reserves.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

As of April 15, 2011, the Company is finishing negotiations to lease office space in Gillette, Wyoming at 3601 Southern Drive, Gillette, Wyoming 82718, where we currently occupy office space. After the Marathon transaction was completed, we remained in the office space on a month to month lease while terms for a new lease are being negotiated. We believe that our facilities are adequate for our current operations.

Item 3. Legal Proceedings

Although we are not party to any material current litigation, we may acquire properties with or become a party to legal actions and proceedings from time to time. We may be unable to estimate legal expenses or losses we may incur, or damages we may recover in these actions, if any, and have not accrued potential gains or losses in our financial statements. Expenses in connection with these actions are recorded as they are incurred.

We believe we carry adequate liability insurance, directors' and officers' insurance, casualty insurance, for owned or leased tangible assets, and other insurance as needed to cover us against claims and lawsuits that occur in the ordinary course of our business. However, an unfavorable resolution of any substantial new matters, and/or our incurrence of legal fees and other costs to defend or prosecute any of these actions may have a material adverse effect on our consolidated financial position, results of operation and cash flows in a particular period.

Item 4. (Removed and Reserved)

N/A

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market for Registrant's Common Equity.

The Company's common stock is quoted in United States markets on the over the counter bulletin board under the symbol "HPGS". There is no assurance that the common stock will continue to be quoted or that any liquidity exists for the Company's shareholders.

The market for the Company's common stock is limited, and can be volatile. The following table sets forth the high and low closing prices relating to the Company's common stock on a quarterly basis for the periods indicated as quoted by the over the counter bulletin board stock market. These quotations reflect inter-dealer prices without retail mark-up, mark-down, or commissions, and may not reflect actual transactions. The numbers also reflect the forward 2 for 1 stock dividend effective December 15, 2010.

Quarter Ended	High Bid	Low Bid
March 31, 2009	$0.207	$0.042
June 30, 2009	$0.165	$0.039
September 30, 2009	$0.053	$0.010
December 31, 2009	$0.010	$0.002
March 31, 2010	$0.005	$0.002
June 30, 2010	$0.001	$0.003
September 30, 2010	$0.014	$0.001
December 31, 2010	$1.15	$0.25
March 31, 2011	$1.40	$0.99
Through April 15, 2011	$1.12	$1.02

Holders. As of the date of this report, the Company had 87 shareholders of record of certificates in physical form, which does not include shareholders whose shares are held in street or nominee names.

As of the date of this report, the Company had 350,000,000 shares of common stock authorized with approximately 166,523,602 shares issued and outstanding and 20,000,000 shares of preferred stock authorized with no shares issued and outstanding.

Penny Stock Regulations. The Company's common stock is quoted in United States markets by the Pink Sheets under the symbol "HPGS." The sale price of the Company's common stock has consistently been reported below $5.00 per share. As such, our common stock may be subject to provisions of Section 15(g) and Rule 15g-9 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), commonly referred to as the "penny stock rule."

Section 15(g) sets forth certain requirements for transactions in penny stocks, and Rule 15g-9(d) incorporates the definition of "penny stock" that is found in Rule 3a51-1 of the Exchange Act. The SEC generally defines "penny stock" to be any equity security that has a market price less than $5.00 per share, subject to certain exceptions. As long as the Company's common stock is deemed to be a penny stock, trading in the shares will be subject to additional sales practice requirements on broker-dealers who sell penny stocks to persons other than established customers and accredited investors.

Dividends. Other than a 2 for 1 forward stock dividend effectively December 15, 2010, the Company has not issued any dividends on the common stock to date, and does not intend to issue any dividends on the common stock in the near future. The Company currently intends to use all profits to further the growth and development of the Company.

Item 6. Selected Financial Data [1] [5]

	December 31, 2010	December 31, 2009
Statement of Operations Summary:		
Total revenues	**$2,611,969**	**$844,239**
Net income (loss) (3)	**($5,483,467)**	**($467,110)**
Net income (loss) per share:		
Basic	**($0.04)**	**($0.01)**
Assuming dilution	**N/A**	**N/A**
Weighted average number of common shares outstanding:		
Basic	**132,963,461**	**65,000,000**
Assuming dilution	**N/A**	**N/A**
Year-end Balance Sheet Summary:		
Cash and cash equivalents	**$208,823**	**$45,426**
Total assets	**47,999,948**	**1,550,743**
Total long-term obligations	**15,972,728**	**350,478**
Total shareholders' equity	**19,596,212**	**(25,750)**

(1) This summary should be read in conjunction with our Consolidated Financial Statements and Notes thereto. All amounts in these notes are rounded to thousands.

(2) The Company changed its fiscal year end from March 31 to December 31 as a result of the reverse merger.

(3) 2010 includes $1,321,660 from oil and gas income.

(4) 2010 includes nonrecurring consulting fees of $532,187 and nonrecurring expenses related to the reverse acquisition of $385,941. We also booked a nonrecurring noncash expense for $3,169,313 related to issuance of discounted shares and a nonrecurring expense of $1,495,000 related to bonuses paid out in connection with two asset acquisitions.

(5) No cash dividends were declared or paid in any year presented.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation

Introduction

Statements about our future expectations are "forward-looking statements" within the meaning of applicable Federal Securities Laws, and are not guarantees of future performance. When used herein, the words "may," "will," "should," "anticipate," "believe," "appear," "intend," "plan," "expect," "estimate," "approximate," and similar expressions are intended to identify such forward-looking statements. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, the following risks and uncertainties:

- *volatility of market prices received for oil and natural gas;*
- *regulatory approvals;*
- *legislative or regulatory changes;*
- *economic and competitive conditions;*
- *debt and equity market conditions;*
- *derivative activities;*
- *exploration risks such as drilling unsuccessful wells;*
- *the ability to obtain industry partners for our prospects on favorable terms to reduce our capital risks and accelerate our exploration activities;*
- *future processing volumes and pipeline throughput;*
- *reductions in the borrowing base under our Credit Facility;*
- *ability to comply with requirements of our Credit Facilities and Debt Instruments;*
- *the potential for production decline rates from our wells to be greater than we expect;*
- *changes in estimates of proved reserves;*
- *potential failure to achieve expected production from existing and future exploration or development projects;*
- *declines in values of our natural gas and oil properties resulting in impairments;*
- *capital expenditures and other contractual obligations;*
- *liabilities resulting from litigation concerning alleged damages related to environmental issues, personal injury, royalties, marketing, title to properties, validity of leases, or other matters that may not be covered by an effective indemnity or insurance;*
- *higher than expected costs and expenses including production, drilling and well equipment costs;*
- *occurrence of property acquisitions or divestitures;*
- *ability to obtain adequate pipeline transportation capacity for our production;*
- *change in tax rates; and*
- *other uncertainties, as well as those factors discussed below and elsewhere in this Annual Report on Form 10-K, particularly in the "Cautionary Note Regarding Forward-Looking Statements' sections and in "item 1A, Risk Factors" all of which are difficult to predict.*

In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. Readers should not place undue reliance on these forward-looking statements, which reflect management's views only as of the date hereof. Other than as required under the securities laws, we do not undertake and any obligation to publicly correct or update any forward-looking statements whether as a result of changes in internal estimates or expectations, new information, subsequent events or circumstances or otherwise.

Overview

High Plains Gas is a Rocky Mountain exploration and production company that seeks to enhance shareholder value by executing a long-term growth strategy. We seek to build stockholder value through profitable growth in reserves and production, which will include investing in and profitably developing key existing development programs as well as growth through exploration and acquisitions. We seek high quality exploration and development projects with potential for providing long-term drilling inventories that generate high returns, but possess the potential to generate revenues from existing assets. Substantially all of our revenues are generated through the sale of natural gas at market prices and the settlement of commodity hedges. Our management team has significant experience acquiring and developing E&P assets in the Rocky Mountains and has an extensive network of industry relationships in the region. Through its solid foundation and experience, the Company intends to pursue expansion plans across this region.

The Company was originally incorporated in Nevada as Northern Explorations, Ltd. ("Northern Explorations") on November 17, 2004. From its inception the Company was engaged in the business of exploration of natural resource properties in the United States. After the effective date of its registration statement filed with the Securities and Exchange Commission (February 14, 2006), the Company commenced quotation on the Over-the-Counter Bulletin Board under the symbol "NXPN."

On July 28, 2010, the Company entered into an agreement to acquire High Plains Gas, LLC, a Wyoming limited liability company ("High Plains LLC") (the "Reorganization Agreement). On September 13, 2010 the Company amended its Articles of Incorporation to change its name to High Plains Gas, Inc. and increase its authorized common stock to 250,000,000 shares. Effective October 29, 2010, the Company completed the acquisition of High Plains Gas, LLC, the entity for the Company's business. The symbol was changed on January 20, 2011 to "HPGS" to more accurately reflect the Company's new name. Under the Reorganization Agreement, shareholders and other parties representing what was Northern Explorations retained 13,000,000 shares (pre-dividend) of the Company's common stock and designees of High Plains LLC were issued 52,000,000 shares (pre-dividend) of the Company's common stock.

The reorganization has been accounted for as a reverse merger and under the accounting rules for a reverse merger, the historical financial statements and results of operations of High Plains Gas, LLC became those of the Company.

As of September 30, 2010, the Company entered into agreements with Current Energy Partners Corporation, a Delaware Corporation ("Current") and its wholly owned subsidiary CEP M Purchase LLC ("CEP"). In accordance with the terms of the agreements, the Company initially purchased a Convertible Note from Current for the amount of $3,550,000 and also provided assistance with CEP's bonding requirements. The proceeds from the Convertible Note as well as approximately $6,000,000 in bank financing were used (described below) by Current through its subsidiary CEP to purchase a significant resource base and land position from Pennaco Energy, Inc. ("Pennaco"), a wholly owned subsidiary of Marathon Oil Company. The assets consisted of Pennaco's "North & South Fairway" assets located in the Basin. These properties encompass approximately 155,000 net operated acres (the "Assets"). The acquisition included the operational capacities including flow lines, transportation rights and production wells both active and idle. The transaction did not transfer deep oil rights, but focused upon mineral rights between the surface and depth above the base Tertiary Paleocene Fort Union Formation generally above 2,500 feet. Under the original agreement, the Company was appointed to perform the operating duties with respect to the assets as specified in the underlying Purchase and Sale Agreement executed on July 21, 2010 by and among Current, CEP and Pennaco (the "Pennaco Agreement").

On December 8, 2010, the Company signed a definitive Stock Purchase Agreement (the "Purchase Agreement") with Big Cat Energy Corporation ("Big Cat") to purchase 20,000,000 shares of Big Cat's restricted common stock, or approximately 31.3% of the projected issued and outstanding shares, at $0.03 per share for $600,000. The purchase price of $600,000 consisted of a combination of $200,000 cash and 739,180 restricted shares of the Company valued at $400,000. The Purchase Agreement also grants the Company warrants to purchase an additional 10,000,000 shares of restricted common stock of Big Cat at $0.15 per share. If the Company exercised the warrants, it would own

30,000,000 shares of Big Cat's common stock or 40.6% of the Company. The warrants have a term of five years from the effective date of the Purchase Agreement. The number of warrants is to be adjusted in the event of a reclassification, change, stock dividend, stock split, combination, reorganization, merger or consolidation affecting the price or number of shares issuable or exercisable under the warrants so as to maintain an approximately equivalent number of shares and exercise price for the warrant holders before and after such a transaction. Any such adjustment is to be made pursuant to official notice from the Company in connection with the transaction. On the closing of this transaction, Big Cat nominated Mark Hettinger, Chairman of the Company, to Big Cat's Board of Directors.

During the fiscal quarter ended December 31, 2010, the Company entered into a $75,000,000 credit facility with Amegy Bank of which $6,000,000 was borrowed to finance the Marathon Acquisition.

Plan of operation

High Plains Gas intends to continue to operate existing methane fields including continuing plans for well reworks and re-activations and gathering systems improvements. As of December 31, 2010, the company operated 1726 producing methane wells of which1043 methane wells were idle. The company was able to bring 33 previously idle methane wells into production from November 19th thru December 31st of 2010. The company expects to continue to bring methane wells into production at a rate of roughly 30 per month throughout the next twelve months.

The company has set a goal for the next twelve months of bringing an additional 1000 mcf/day of methane to point of sale each month. This goal is expected to be achieved through rework of idle methane wells and well re-activation in the fields purchased from Marathon Oil in November of 2010. The company may also choose to drill new methane wells in order to increase production in fields in which we have the right to do so.

In addition to day-to-day operation of the company's existing properties, the company intends to grow both assets and revenue through acquisitions of properties with existing production and upside potential through the development of currently undeveloped and underdeveloped lease acreage. The company intends to finance the acquisition of future properties through a combination of equity financing and debt financing. The company believes that opportunities exist in the marketplace for the acquisition of existing production with higher cost structures relative to what the company believes is necessary for successful operation of the properties. The company believes that because of the extended reduction in the net price to producers for methane sold, properties with higher cost structures are willing to sell existing production at purchase prices favorable to High Plains Gas, and that High Plains Gas can operate these properties at increased profit margins relative to other producers.

Though the company has no plans for instituting a drilling program at the current time, the ownership of undeveloped acreage creates that potential that the company may seek to begin a drilling program in the future. The purpose of this drilling program would be to maintain or increase existing methane production. Another purpose of this program may, at a future date, be to develop and operate oil producing wells on acreage that the company holds, or may hold, such rights. The extent of any drilling program for natural gas or oil will be subject to permitting and capital available to fund such a program. The company may choose to raise capital for a drilling program through both equity and debt financing.

Because of our rapid growth through acquisitions, and the anticipated development of our properties, our historical results of operations and period-to-period comparisons of these results and certain financial data may not be meaningful. In addition past results are not indicative of future results.

Our acquisitions and capital expenditures were financed with a combination of funding from equity investments in our company, debt financing, our Credit Facility and cash flow from operations.

Commodity prices, particularly in the Rocky Mountain region, are inherently volatile and are influenced by many factors outside of our control. We plan our activities and capital budget using what we believe to be conservative sales price assumptions and our existing hedge position. Our strategic objective is to hedge 40% to 60% of our anticipated production on a forward 12-24 month basis. We focus our efforts on increasing natural gas and oil reserves and production while controlling costs at a level that is appropriate for long-term operations. Our future earnings and cash flows are dependent on our ability to manage our revenues and overall cost structure to a level that allows for profitable production.

Like all oil and gas exploration and production companies, we face the challenge of natural production declines. As reservoir pressures are depleted, oil and gas production from a typical well naturally decrease. Thus, an oil and gas exploration and production company depletes part of its asset base with each unit of oil or natural gas it produces. We attempt to overcome this natural decline by drilling to find additional reserves and acquiring more reserves than we produce. Our future growth will depend on our ability to continue to add reserves in excess of production. We will maintain our focus on costs to add reserves through drilling and acquisitions as well as the costs necessary to produce such reserves. Our ability to add reserves through drilling is dependent on our capital resources and can be limited by many factors, including our ability to timely obtain drilling permits and regulatory approvals. The permitting and approval process has been more difficult in recent years than in the past due to more stringent rules, increased activism from environmental and other groups, which as extended the time it takes us to receive permits, and other necessary approvals. Because of our relatively small size and concentrated property base, we can be disproportionately disadvantaged by delays in obtaining or failing to obtain drilling approvals compared to companies with larger or more dispersed property bases. As a result, we may be less able to shift drilling activities to areas where permitting may be easier, and we have fewer properties over which to spread the costs related to complying with these regulations and the costs or foregone opportunities resulting from delays.

The Company obtains revenue by procuring, producing and marketing natural gas (Methane) from the Powder River Basin (the “Basin”) in Central Wyoming. The Company’s management team has significant experience acquiring and developing E&P assets in the Rocky Mountains and has experience in cultivating industry relationships. Through its solid foundation and experience in the region, the Company intends to pursue expansion plans both within the Basin and across the Rocky Mountain region.

Please note that unless otherwise indicated, the information in this report gives effect to 1 for 1 dividend of the Common Stock effected on December 15, 2010, as well as the other historical stock dividends and splits.

Recent Developments

On January 24, 2011, the Company’s Board of Directors amended the Company’s bylaws to provide for a five member Board of Directors, and appointed Gary Davis, Cordell Fonnesbeck and Alan R. Smith as directors in addition to the already appointed directors, Mark D. Hettinger and Joseph Hettinger.

On February 2, 2011, the Company signed a Purchase and Sale Agreement with J.M. Huber Corporation (the “Huber Purchase Agreement”) in which the Company agreed to purchase approximately 313,000 net acres of leasehold and 2,302 wells in the Basin for $35,000,000 (the “Huber Acquisition”). The Company has provided $2,000,000 in non-refundable cash deposits and later an additional $1,500,000 in “HPGS” common stock which will either be returned or be credited to the purchase price at the time of closing.

On February 24, 2011, the Company entered into an agreement with Fletcher International, Ltd. (“Fletcher”) pursuant to which it sold Fletcher warrants to purchase $5,000,000 in shares of the Company’s common stock for a purchase price of $1,000,000. The exercise price for Common Stock to be purchased in the warrants issued to Fletcher is the lesser of (i) $1.25 and (ii) the average of the volume weighted average market price for all of the business days in the calendar month immediately preceding the date of the first notice of exercise of the Warrants, but in no event can the exercise price be less than $0.50. The warrants include a cashless exercise provision. The proceeds of the Fletcher warrants were utilized as a deposit for the Huber Purchase Agreement.

On March 31, 2011, the Company signed an amendment to the Huber Purchase Agreement in which both parties agreed to extend the closing date to April 29, 2011. The Company agreed to provide 1,500,000 shares of stock in a non-refundable deposit in exchange for this extension. The shares will either be credited to the purchase price or returned at closing.

Results of Operations

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

The following table sets forth selected operating data for the periods indicated:

	2010	2009
Revenues:		
Gas and oil revenue	$ 2,464,552	$ 520,620
Pipeline revenue	110,506	235,689
Other	36,911	87,930
Total Revenue	2,611,969	844,239
Costs and Expenses		
Lease operating expense and production taxes	3,230,426	613,873
General and administrative expense	3,288,816	210,454
Depreciation, depletion and amortization	1,306,617	432,051
Accretion of asset retirement obligation	65,979	2,139
Total Costs and Expenses	7,891,838	1,258,517
Operating (Loss)	(5,279,869)	(414,278)
Other Income (Expense)		
Other income	481,302	9,889
Gain on valuation of equity securities	1,935,234	--
Amortization of bond commitment and financing fees	(291,667)	--
Commodity derivative adjustment	(603,742)	--
Interest (expense)	(1,724,745)	(62,721)
Total Other Income (Expense)	(203,618)	(52,832)
Net Income (Loss)	$ (5,483,487)	$ (467,110)

Production Revenues and Volumes. Production revenues increased to $2,611,969 for the year ended December 31, 2010 from $844,239 million for the year ended December 31, 2009 due to acquisition of oil and gas properties from Pennaco Energy, Inc., a wholly owned subsidiary of Marathon Oil Company (“Marathon Transaction”) and an increase in natural gas commodity pricing basis after the effects of realized cash flow hedges. The effects of realized hedges only include settlements from hedging instruments that were designated as cash flow hedges. See below for more information related to the Commodity derivative gain (loss) line item.

The production volumes increased to 749,461 Mcf for the year ended December 2010 from 201,831 Mcf for the year ended December 31, 2009. The increase was primarily attributed to the Marathon Transaction.

Hedging Activities. As of December 31, 2010, approximately 40% of our natural gas volumes were subject to financial hedges, which resulted in an increase in natural gas revenues of $17,050 after settlements for all derivatives. In 2009, the Company had no financial hedges in place. It is expected that as we continue to increase production, we will have 40-60% of our natural gas volumes subject to financial hedges.

Commodity Derivative Gain (Loss). The “Commodity derivative gain (loss)” line item on the Consolidated Statements of Operations is comprised of ineffectiveness on cash flow hedges and realized and unrealized gains and losses on hedges that do not qualify for cash flow hedge accounting. Unrealized gains and losses represent the change in the fair value of the derivative instruments that do not qualify for cash flow hedge accounting. As those instruments settle, their settlement will be presented as realized gains and losses within this same lime item.

The overall commodity derivative gain (loss) from was ($603,742) for the year ended December 31, 2010. There were no commodity derivatives for the year ended December 31, 2009. The loss was primarily due to the unrealized losses resulting in the change in future natural gas contracts.

Gain on valuation of equity securities. As allowed by ASC 825-10, the Company has elected to follow the fair value option for reporting the securities received from Big Cat Energy Corporation, thus the fair value adjustment of $1.9 million is reflected in 2010 operating results.

Lease Operating Expenses. Lease operating expense increased to $3,230,426 in 2010 from $613,873 in 2009. The increase was primarily due to the Marathon Transaction and expenditures during December 2010 to open previously shut-in reserves.

Gathering, Transportation and Processing Expense. Gathering, transportation and processing expense increased to $605,009 in 2010 from $0 (a nominal amount) in 2009. The increase was primarily due to the Marathon Transaction. Although we don’t anticipate increases in our fixed demand charges, we may incur additional costs from other pipelines in the future.

Production Tax Expense. Total production taxes increased to $454,566 in 2010 from $10,023 in 2009. The increase in production taxes is primarily related to the Marathon Transaction. Production taxes are primarily based on the wellhead values of production, which exclude gains and losses associated with hedging activities.

Production tax rates vary across the different areas in which we operate. As the proportion of our production changes from area to area, our average production tax rate will vary depending on the quantities produced from each area and the production tax rates in effect for those areas.

Impairment Dry Hole Costs and Abandonment Expenses. Our impairment, dry hole costs and abandonment expense is $0 for year ended December 31, 2010 and $0 for year ended December 31, 2009.

We test for impairment of our properties based on estimates of proved reserves. Proved oil and gas properties are reviewed for impairment whenever events or circumstances indicate that the carrying amount may not be recoverable. We estimate the future undiscounted cash flows of the affected properties to judge the recoverability of the carrying amounts. Initially this analysis is based on proved reserves. However, when we believe that a property contains oil and gas reserves that do not meet the defined parameters of proved reserves, an appropriately risk adjusted amount of these reserves may be included in the impairment evaluation. These reserves are subject to much greater risk of ultimate recovery.

An asset would be impaired if the undiscounted cash flows were less than its carrying value. Impairments are measured by the amount by which the carrying value exceeds its fair value. Impairment analysis is performed on an ongoing basis. In addition to using estimates of oil and gas reserve volumes in conducting impairment analysis, it is also necessary to estimate future oil and gas prices and costs, considering all available evidence at the date of review. The impairment evaluation triggers include a significant long-term decrease in current and projected prices or reserve volumes, an accumulation of project costs significantly in excess of the amount originally expected and historical and current negative operating losses. Although we evaluate future oil and gas prices as part of the impairment analysis, we do not view short-term decreases in prices, even if significant, as impairment triggering events.

Unproved oil and gas properties that are individually significant are periodically assessed for impairment of value, and a loss is recognized at the time of the impairment by providing an impairment allowance. An asset would be impaired if the undiscounted cash flows were less than its carrying value. Impairments are measured by the amount by which the carrying value exceeds its fair value. Because the Company uses the successful efforts method, the Company assesses its properties individually for impairment, instead of on an aggregate pool of costs.

Depreciation, Depletion and Amortization ("DD&A"). DD&A was $1,306,617 in 2010 compared to $432,051 in 2009. The increase in DD&A was attributed to increased production levels during 2010 due to the Marathon Transaction.

Capitalized costs of producing oil and gas properties, after considering estimated residual salvage values, are depreciated and depleted by the unit-of production method. This method is applied through the simple multiplication of reserve units produced by the leasehold costs per unit on a field by field basis. Leasehold cost per unit is calculated by dividing the total cost of acquiring the leasehold by the estimated total proved oil and gas reserves associated with that lease. Field cost is calculated by dividing the total cost by the estimated total proved producing oil and gas reserves associated with that field.

General and Administrative Expense. General and administrative expense increased to $3,288,816 in 2010 from $210,454 in 2009. Non-cash stock-based compensation totaled $1,052,683 for 2010 and $0 for 2009. Consulting and other professional fees increased by $932,430 due to the Marathon Transaction and the inherent costs attributed to being a registrant. The remaining increase was primarily due to an increase in employee compensation costs and benefit programs attributed to additional employees that were hired after the Marathon transaction.

Interest Expense.   Interest expense increased to $1,724,745 in 2010 from $62,721 in 2009 due to an increase in debt levels or approximately $14,600,000.

Net (loss) increased by ($5.0) million, from ($467,110) in 2009 to ($5,483,487) in 2010.

Capital Resources and Liquidity

During 2010, the Company issued a total of 2,335,000 shares for a combination of bond commitment fees, compensation, professional services and convertible debt.

Our primary sources of liquidity our formation has been net cash provided by operating activities, sales and other issuances of equity and debt securities. Our primary use of capital has been for the development and acquisition of natural gas properties. As we pursue profitable reserves and production growth, we continually monitor the capital resources, including issuance of equity and debt securities, available to us to meet our future financial obligations, planned capital expenditure activities and liquidity. Our future success in growing proved reserves and production will be highly dependent on capital resources available to us and our success in finding or acquiring additional reserves. We actively review acquisition opportunities on an ongoing basis. If we were to make significant additional acquisitions for cash, we may need to obtain additional equity or debt financing, which may be at a higher cost than previous issuances.

Our liquidity requirements arise principally from our working capital needs, including funds needed to operate our oil and gas business, as well as targeted acquisitions.

On November 19, 2010 CEP-M Purchase LLC ("CEPM), which was acquired on or about November 19, 2010 by the Company, entered into a Credit Agreement (the "Credit Agreement") with Amegy Bank National Association ("Amegy") and other associated lenders. The Credit Agreement provides for a revolving line of credit and letter of credit facility of up to $75,000,000, with an initial commitment amount of $6,000,000. The Credit Agreement terminates on November 19, 2013 and provides for interest at Amegy's prime rate (adjustable under certain circumstances). The Credit facility includes a 0.5% commitment fee payable per annum on available commitments and certain other fees, and has numerous positive and negative covenants required to maintain the facility. The Credit Agreement is secured by essentially all of the oil and gas assets of CEPM pursuant to a Security Agreement. Upon execution of the Credit Agreement, CEPM utilized the $6,000,000 available under the Credit Agreement as partial payment in the acquisition of the Marathon Assets.

As of year ended December 31, 2010, we had negative working capital of ($4,108,289) compared to $859,841 at year ended December 31, 2009. We will seek additional sources of capital for the coming year. The negative working capital at December 31, 2010 results from $6,000,000 debt classified as a current liability due to debt covenant violations and from $352,579 of lines of credit which are due within the next year.

During the year ended December 31, 2010 the Company completed a reverse merger with Northern Exploration, as part of this merger the Company declared a 1 for 200 stock split which resulted in 498,601 shares issued and outstanding. In conjunction with the merger, the Company issued 7,000,000 shares at $.016 and 5,501,400 shares at $.05 to convert $395,338 of debt into equity. In addition the Company issued 52,000,000 shares (pre stock dividend referenced below) of restricted common stock to the members of High Plains LLC for an 80% ownership in the Company. On December 19,2010 the Company completed a one share for each existing share stock dividend which increased all outstanding shares of the Company.

On December 6, 2010, the Company declared a one share for each existing share stock dividend to all holders of record on that date and issued 65,000,011 shares of common stock to its holders of record.

The Company has issued 5,360,000 shares of common stock in private placements to qualified investors.

The Company purchased approximately 35% of Big Cat for $200,000 cash and 729,180 shares of restricted common stock valued at $.69 per share and acquired the remaining interest in CEP_M Purchase for a note payable of $1,500,000 and 22,500,000 shares of restricted common stock at $.69 per share during the year ended December 31, 2010.

After the above referenced transactions, the Company had 160,934,202 shares issued and outstanding at December 31, 2010

We believe we will successfully operate our wells and collect funds due on sales. Although there can be no assurance that we will be successful in our efforts, we believe the combination of our cash on hand and revenue from executing our strategy will be sufficient to meet our obligations of current and anticipated operating cash requirements beyond fiscal 2011. If necessary, we will meet anticipated operating cash requirements by reducing costs, and/or pursuing sales of certain assets, or through seeking additional debt or equity financings.

Contingencies

Our directors, officers, employees and agents may claim indemnification in certain circumstances. We seek to limit and reduce potential obligations for indemnification by carrying directors and officers liability insurance, subject to deductibles.

We also carry liability insurance, casualty insurance, for owned or leased tangible assets, and other insurance as needed to cover us against potential and actual claims and lawsuits that occur in the ordinary course of business.

Funding and Capital Requirements

Equity Financing

Beginning in October 2010 and continuing through March 2011, the Company undertook a private placement transaction pursuant to which it sold an aggregate of 8,615,000 shares of common stock for $4,307,500 to a total of 78 accredited investors.

On February 17, 2011 the Company entered into Promissory Notes with two accredited investors for total proceeds of $1,000,000. Those promissory notes were due and were repaid on February 28, 2011. The proceeds were utilized as a portion of the deposit required for the Huber acquisition. As part of the transaction, the investors were issued warrants to purchase shares of the Company's common stock.

On February 24, 2011, the Company entered into an agreement with Fletcher International, Ltd. ("Fletcher") pursuant to which it sold Fletcher warrants to purchase $5,000,000 in shares of the Company's common stock for a purchase price of $1,000,000. The exercise price for Common Stock to be purchased in the warrants issued to Fletcher is the lesser of (i) $1.25 and (ii) the average of the volume weighted average market price for all of the business days in the calendar month immediately preceding the date of the first notice of exercise of the Warrants, but in no event can the exercise price be less than $0.50. The warrants include a cashless exercise provision. The proceeds of the Fletcher warrants were utilized as a deposit for the Huber Purchase Agreement.

Financial Instruments and Other Information

As of December 31, 2010 and 2009, we had cash, accounts receivable, accounts payable, notes payable and accrued liabilities, which are each carried at approximate fair market value due to the short maturity date of those instruments. Unless otherwise noted, it is management's opinion that the Company is not exposed to significant interest, currency or credit risks arising from these financial instruments.

Critical Accounting Policies

Use of Estimates in the Preparation of Financial Statements. We prepare our consolidated financial statements in this report using accounting principles that are generally accepted in the United States ("GAAP"). GAAP represents a comprehensive set of accounting disclosure rules and requirements. We must make judgments, estimates, and in certain circumstances, choices between acceptable GAAP alternatives as we apply these rules and requirements. The most critical estimate we make is the engineering estimate of proved oil and gas properties and the estimate of the impairment of our oil and gas properties. It also affects the estimated lives used to determine asset retirement obligations. In addition, the estimates of proved oil and gas reserves are the basis for the related standardized measure of discounted future net cash flows. Although actual results may differ from these estimates under different assumptions or conditions, the Company believes that its estimates are reasonable.

Estimated proven oil and gas reserves. The evaluation of our oil and gas reserves is critical to management of our operations and ultimately our economic success. Decisions such as whether a development of a property should proceed and what technical methods are available for development are based on an evaluation of reserves. These oil and gas reserve quantities are also used as the basis of calculating the unit-of-production rates for depreciation, evaluating impairment and estimating the life of our producing oil and gas properties in our asset retirement obligations. Our total reserves are classified as proved, possible and probable. Proved reserves are classified as either proved developed or proved undeveloped. Proved developed reserves are those reserves which can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves include reserves expected to be recovered from new wells from undrilled proven reservoirs or from existing wells where a significant major expenditure is required for completion and production. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves and when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable estimates. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves and when probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed proved plus probable plus possible reserve estimates.

Independent reserve engineers prepare the estimates of our oil and gas reserves presented in this report based on guidelines promulgated under GAAP and in accordance with the rules and regulations of the Securities and Exchange Commission. The evaluation of our reserves by the independent reserve engineers involves their rigorous examination of our technical evaluation and extrapolations of well information such as flow rates and reservoir pressure declines as well as other technical information and measurements. Reservoir engineers interpret these data to determine the nature of the reservoir and ultimately the quantity of total oil and gas reserves attributable to a specific property. Our total reserves in this report include only quantities that we expect to recover commercially using current prices, costs, existing regulatory practices and technology. While we are reasonably certain that the total reserves will be produced, the timing and the ultimate recovery can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals and changes in projections of long-term oil and gas prices. Revisions can include upward or downward changes in the previously estimated volumes or proved reserves for existing fields due to evaluation of (1) already available geologic, reservoir or production data or (2) new geologic or reservoir data obtained from wells. Revisions can also include changes associated with significant changes in development strategy, oil and gas prices or production equipment/facility capacity.

Standardized measure of discounted cash flows. The standardized measure of discounted future net cash flows relies on these estimates of oil and gas reserves using commodity prices and costs at year-end. Natural gas prices were calculated for each property using the differentials to an average for the year of the first of the month Henry Hub Louisiana Onshore price. The standardized measure is based on the average of the beginning of the month pricing for 2010. While we believe that future operating costs can be reasonably estimated, future prices are difficult to estimate since the market prices are influenced by events beyond our control. Future global economic and political events will most likely result in significant fluctuations in future oil and gas prices.

Successful Efforts Method Accounting. The Company uses the successful efforts method of accounting for oil and gas producing activities. Oil and gas exploration and production companies choose one of two acceptable accounting methods, successful efforts or full cost. The most significant difference between the two methods relates to the accounting treatment of drilling costs for unsuccessful exploration wells "dry holes") and exploration costs. Under the successful efforts method, exploration costs and dry hole costs (the primary uncertainty affecting this method) are recognized as expenses when incurred and the costs of successful exploration wells are capitalized as oil and gas properties. Entities that follow the full cost method capitalize all drilling and exploration costs including dry hole costs into one pool of total oil and gas property costs.

While it is typical for companies that drill exploration wells to incur dry hole costs, our primary activities during 2010 focused on development and re-opening existing well-bores. Nevertheless, it is anticipated that we will selectively expand our exploration drilling in the future. It is impossible to accurately predict specific dry holes. Because we cannot predict the timing and magnitude of dry holes, quarterly and annual net income can vary dramatically.

The calculation of depreciation, depletion and amortization of capitalized costs under the successful efforts method of accounting differs from the full cost method in that the successful efforts method requires us to calculate depreciation, depletion and amortization expense on individual properties rather than one pool of costs. In addition, under the successful efforts method we assess our properties individually for impairment compared to one pool of costs under the full cost method.

Depreciation and Depletion of Oil and Natural Gas Properties. Capitalized costs of producing oil and gas properties, after considering estimated residual salvage values, are depreciated and depleted by the unit-of production method. This method is applied through the simple multiplication of reserve units produced by the leasehold costs per unit on a field by field basis. Leasehold cost per unit is calculated by dividing the total cost of acquiring the leasehold by the estimated total proved oil and gas reserves associated with that lease. Field cost is calculated by dividing the total cost by the estimated total proved producing oil and gas reserves associated with that field.

Risks and Uncertainties. Historically, oil and gas prices have experienced significant fluctuations and have been particularly volatile in recent years. Price fluctuations can result from variations in weather, levels of regional or national production and demand, availability of transportation capacity to other regions of the country and various other factors. Increases or decreases in prices received could have a significant impact on future results.

Stock-Based Compensation. Stock-based compensation and warrants are measured in accordance with the guidance of ASC Topic 718, Compensation – Stock Compensation ("ASC 718") at the grant date based on the value of the awards using the Black Scholes Option pricing model and are recognized on a straight-line basis over the requisite service period (usually the vesting period). The Company estimates forfeitures in calculating the cost related to stock-based compensation as opposed to recognizing these forfeitures and the corresponding reduction in expense as they occur. Compensation expense is then adjusted based on the actual number of awards for which the requisite service period is rendered. A market condition is not considered to be a vesting condition with respect to compensation expense. Therefore, an award is not deemed to be forfeited solely because a market condition is not satisfied.

Asset Retirement Obligation. The Company follows FASB ASC 410 – Asset Retirement and Environmental Obligations which requires entities to record the fair value of a liability for legal obligations associated with the retirement obligations of tangible long-lived assets in the period in which it is incurred. The fair value of asset retirement obligation liabilities has been calculated using an expected present value technique. Fair value, to the extent possible, should include a fair market risk premium for unforeseeable circumstances. When the liability is initially recorded, the entity increases the carrying amount of the related long-lived asset. Over time, accretion of the liability is recognized each period and the capitalized cost is amortized over the useful life of the related asset. Upon retirement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. This standard requires the Company to record a liability for the fair value of the dismantlement and plugging and abandonment costs, excluding salvage values.

Derivatives. Derivative financial instruments, utilized to manage or reduce commodity price related to the Company's production, are accounted for under the provisions of FASB ASC 815 – Derivatives and Hedging. Under this statement, derivatives are carried on the balance sheet at 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 earnings. If the derivative is designated as a cash flow hedge, the effective portions of changes in the fair value of the derivatives are recorded in other comprehensive income or loss and are recognized in the statement of operations when the hedged item affects earnings. If the derivative is not designated as a hedge, changes in the fair value are recognized in other expense. Ineffective portions of changes in the fair value of cash flow hedges are also recognized in loss on derivative liabilities.

As of December 31, 2011, the Company was required to hedge production of 5,500 MMBtu / day until December 2012.

Fair Value Measurements. The Company has elected to follow the fair value option for reporting the securities from Big Cat Energy Corporation. This election will require the Company to mark these securities to fair value at each reporting period.

The Company follows current accounting guidelines in measuring and disclosing their financial instrument's fair values. Fair Values are determined using three levels of fair value hierarchy:

- Level 1 – quoted prices in active markets for identical assets or liabilities;

- Level 2 – inputs, other than the quoted prices in active markets that are observable either directly or indirectly; and

- Level 3 – unobservable inputs based on the Company's own assumptions.

Recent Accounting Pronouncements

In June 2009, the FASB approved the FASB Accounting Standards Codification ("ASC"), which after its effective date of July 1, 2009 is the single source of authoritative, nongovernmental U.S. Generally Accepted Accounting Principles (GAAP). The Codification reorganizes all previous U.S. GAAP pronouncements into roughly 90 accounting topics and displays all topics using consistent structure. All existing standards that were used to create the Codification are now superseded, replacing the previous references to specific Statements of Financial Accounting Standards ("SFAS") with numbers used in the Codification's structural organization. The adoption of this guidance did not have a material impact on our financial statements. We have updated our disclosures accordingly.

We have reviewed all recently issued, but not yet effective, accounting pronouncements and do not believe the future adoption of any such pronouncements may be expected to cause a material impact on our financial condition or the results of our operations.

Recent changes to SEC Regulation S-K and S-X pertaining to *Modernization of Oil and Gas Reporting* include changes to the price used to compute reserves, the definition of reserves, the use of technology and the optional disclosure of probable and possible reserves. The new regulations are effective for years ending after December 15, 2009.

Reliance on one revenue source

During the fiscal year ended December 31, 2010, we had a significant concentration of revenue from the marketing and sale of natural gas. Our business model provides for us to hedge our revenues to some extent by acquiring additional properties, however, we intend to rely upon the sale of natural gas.

Operating Leases

As of April 1, 2011, the Company is finishing negotiations to lease office space in Gillette, Wyoming at 3601 Southern Drive, Gillette, Wyoming 82718, where we currently occupy office space. After the Marathon transaction was completed, we remained in the office space on a month to month lease while terms for a new lease are being negotiated. We believe that our facilities are adequate for our current operations.

Employment contracts

The Company is party to several employment agreements with key personnel, all of which are effective for a 12-month period beginning January 1, 2011. The agreements range from $80,000 to $175,000 per year and all agreements contain customary terminology as to termination criteria.

Delivery Commitments

A portion of our production is sold under certain contractual arrangements that specify the delivery of a fixed and determinable quantity. The following table sets forth information about material long- term firm transportation contracts for pipeline capacity. These contracts were acquired as part of the acquisition of the Pennaco "North & South Fairway Assets." Under these firm transportation contracts, we are obligated to deliver minimum daily gas volumes, or pay the respective transportation fees for any deficiencies in deliveries. Although exact amounts vary, as of December 31, 2010 we were committed to deliver the following fixed quantities of our natural gas production:

Type of Arrangement	Pipeline System / Location	Deliverable Market	Gross Deliveries (MMBtu/d)	Term
Firm Transport	WIC Medicine Bow	Rocky Mountains	15,000	07/10 –11/15
Firm Transport	Kinder Morgan Trailblazer	Rocky Mountains	22,500	07/10 - 05/12
Firm Transport	Copano Fort Union	Rocky Mountains	10,000	07/10 - 11/11

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 risks. The term "market risk" refers to the risk of loss arising from adverse changes in natural gas and oil prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our primary market risk exposure is in the prices we receive for our production. Realized pricing is primarily driven by the prevailing worldwide price for spot market prices applicable to our U.S. natural gas production. Pricing for natural gas has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for future production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index price.

We routinely enter into financial hedges relating to a portion of our projected production revenue through various financial transactions that hedge future prices received. If the applicable monthly price indices are different from the realized pricing, we and the counterparty to the hedges would be required to settle the difference. These financial hedging activities are intended to support natural gas at targeted levels that provide an acceptable rate of return and to manage our exposure to natural gas price fluctuations.

As of March 27, 2011, we have financial derivative instruments related to natural gas in place for the following periods indicated. Further detail of these hedges is summarized in the table presented under "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

	For the Year Ended December 31,	
	2011	2012
Natural Gas (MMBtu)	66,000	50,500

Item 8. Financial Statements and Supplementary Data

The information required by this item is included below in "Item 15. Exhibits, Financial Statement Schedules".

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosures

Engagement of new independent registered public accounting firm

Effective December 9, 2010 we engaged Eide Bailly LLP ("Eide Bailly")as our independent registered public accounting firm with the approval of our board of directors. Accordingly, we terminated Chang G. Park, CPA, the previous auditor, effective December 9, 2010. Chang G. Park, CPA's report on the financial statements as of and for the year ended March 31, 2009 and March 31, 2010 did not contain an adverse opinion or disclaimer of opinion and was not modified as to uncertainty, audit scope, or accounting principles save and except for a "going concern" qualification provided with the overall audit opinion. Eide Bailly was not consulted on any matter relating accounting principles to a specific transaction, either completed or proposed, the type of an audit opinion that might be rendered on our financial statements or a reportable event. From March 31, 2009 through the subsequent year ended March 31, 2010, and since that year end, there were no disagreements with Chang G. Park, CPA on any matter of accounting principles or practices, financial statement disclosure, or auditing scope procedure, which disagreements, if not resolved to the satisfaction of Chang G. Park, CPA, would have caused Chang G. Park, CPA, to make reference to the subject matter of the disagreement in its reports on our consolidated financial statements for such periods. We provided Chang G. Park, CPA with a copy of a current report on Form 8-K prior to its filing with the SEC, and requested that they furnish us with a letter addressed to the SEC stating whether they agree with the statements made in this Current Report on Form 8-K, and if not, stating the aspects with which they do not agree. A copy of the letter provided from Chang G. Park, CPA was filed as Exhibit 16.1 to the Form 8-K dated December 9, 2010 and no disagreement was reported

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures and Remediation

As required by Rule 13(a)-15 under the Exchange Act, in connection with this annual report on Form 10-K, under the direction of our Chief Executive Officer and Chief Financial Officer, we have evaluated our disclosure controls and procedures as of December 31, 2010, including the remedial actions discussed below, and we have concluded that, as of December 31, 2010, our disclosure controls and procedures were ineffective as discussed in greater detail below. As of the date of this filing, we are still in the process of remediating such material weaknesses in our internal controls and procedures.

It should be noted that while our management believes our disclosure controls and procedures provide a reasonable level of assurance, they do not expect that our disclosure controls and procedures or internal controls will prevent all error and all fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. These inherent limitations include the realities that judgments in decision making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of internal control is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, controls may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

Management's Annual Report on Internal Control over Financial Reporting

Management is responsible for establishing and maintaining internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Our management evaluated, under the supervision and with the participation of our Chief Executive Officer, the effectiveness of our internal control over financial reporting as of December 31, 2010.

Based on its evaluation under the framework in Internal Control – Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission, our management concluded that our internal control over financial reporting was not effective as of December 31, 2010, due to the existence of significant deficiencies constituting material weaknesses, as described in greater detail below. A material weakness is a control deficiency, or combination of control deficiencies, such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis.

Limitations on Effectiveness of Controls

Our Chief Executive Officer and Chief Financial Officer does not expect that our disclosure controls or our internal control over financial reporting will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of a simple error or mistake. Additional controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions; over time, controls may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

Material Weaknesses Identified

In connection with the preparation of our consolidated financial statements for the year ended December 31, 2010, certain significant deficiencies in internal control became evident to management that represent material weaknesses, including:

i. Lack of audit committee. We currently have no audit committee who would be charged with the purpose of overseeing the accounting and financial reporting processes of the Company.

ii. Insufficient segregation of duties in our accounting functions and limited personnel. During the year ended December 31, 2010, we had limited staff that performed nearly all aspects of our financial reporting process, including, but limited to access to the underlying accounting records and systems, the ability to post and record journal entries and responsibility for the preparation of financial statements. This creates certain incompatible duties and a lack of review over the financial reporting process that would likely result in a failure to detect errors in spreadsheets, calculations, or assumptions used to compile the financial statements and related disclosures as filed with the SEC. These control deficiencies could result in a material misstatement to our interim or annual consolidated financial statements that would not be prevented or detected.

In addition, our Company's accounting personnel do not have sufficient technical accounting knowledge relating to accounting for complex U.S. generally accepted accounting principle matters. Management corrected any errors prior to the release of our Company's December 31, 2010 consolidated financial statements.

Plan for Remediation of Material Weaknesses

We intend to take appropriate and reasonable steps to make the necessary improvements to remediate these deficiencies. We intend to consider the results of our remediation efforts and related testing as part of our year-end 2011 assessment of the effectiveness of our internal control over financial reporting.

We intend to undertake the below remediation measures to address the material weaknesses described in this annual report at our earliest opportunity. Such remediation activities include the following:

i. We continue to recruit additional independent board members to join our board of directors and will consider the adoption of an audit committee at such time that additional board members are retained.

ii. We intend to retain additional accounting personnel as well as individuals qualified to assist in the preparation of our public filings and assist in accounting matters and we intend to continue to update the documentation of our internal control processes, including formal risk assessment of our financial reporting processes.

Changes in Internal Controls over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended December 31, 2010 that have materially affected or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Director and Executive Officer Summary

The following table sets forth the names, ages, and principal offices and positions of the Company's current directors, executive officers, and persons the Company considers to be significant employees. The Board of Directors elects the Company's executive officers annually. the Company's directors serve one-year terms or until their successors are elected, qualified and accept their positions. The executive officers serve terms of one year or until their death, resignation or removal by the Board of Directors. Other than Joseph Hettinger who is the son of Mark D. Hettinger, there are no family relationships or understandings between any of the directors and executive officers. In addition, there was no arrangement or understanding between any executive officer and any other person pursuant to which any person was selected as an executive officer.

Name of Director or Officer	Age	Position
Brent M. Cook	50	Chief Executive Officer
Mark D. Hettinger	51	Director, President and Chief Operating Officer
Joseph Hettinger	29	Director and Chief Financial Officer
Brandon Hargett	39	Vice President Strategy & Business Development
Gary Davis	56	Director
Cordell Fonnesbeck	63	Director
Alan Smith	71	Director

Executive Officer and Director Bios

Brent M. Cook, Chief Executive Officer

Mr. Cook has served as the Company's Chief Executive Officer since February 16, 2011. Prior to joining the Company, Mr. Cook served as CEO and a member of the Board of Directors of Current Energy Partners Corporation, a privately held Delaware Corporation. Current was held the acquiring entity of CEP-M Purchase, LLC until it sold its interest for common stock in High Plains Gas, Inc. Previous to Current Energy, Mr. Cook served as a director of Raser Technologies Inc., a publicly traded energy technology company listed on the NYSE ("Raser" NYSE:RZ) from October 2004 until August 2009 and as Raser's Chief Executive Officer from January 2005 until August 2009. From 1996 to 2002, Mr. Cook served in various positions at Headwaters Inc. (NYSE: HW), a large publicly-traded energy technology company, including Chief Executive Officer, President, and Chairman of the Board of Directors. Prior to his joining Headwaters Inc., Mr. Cook was Director of Strategic Accounts, Utah Operations, at PacifiCorp, which operates as a local electric utility in seven western states. Mr. Cook spent 12 years at PacifiCorp with specific expertise in transmission interconnection and power sales agreements. Mr. Cook was also employed from 2002-2005 by AMP Resources, a geothermal power generation company that later sold their projects to ENEL, an Italian power generation company.

Mark D. Hettinger, Director, President and Chief Operating Officer

Mr. Hettinger has over 30 years of experience in oil and gas construction, fabrication and process equipment. Mr. Hettinger founded Hettinger Welding in 1980 to provide welding and fabrication services to energy companies in Wyoming. In October 2006, after 28 years as principal owner and CEO, Mr. Hettinger sold Hettinger Welding. Mr. Hettinger's unique vision and professional ambition grew Hettinger Welding to over 1,400 employees and a $200 million plus dollar annual market share, solidifying Hettinger Welding as one of the largest oil and gas construction firms in the Western United States. In 2009, Mr. Hettinger retired as CEO of Hettinger Welding to focus on oil and gas production and became managing member of High Plains Gas, LLC, which was acquired by the Company in connection with the Reorganization Agreement.

Joseph Hettinger, Director and Chief Financial Officer

Mr. Hettinger has over 10 years of experience in accounting and finance in the banking and energy industries. Mr. Hettinger co-authored the internal control structure for Sarbanes Oxley Sec. 404 for a publicly traded bank in 2004. In 2004, Mr. Hettinger co-founded Rocky Mountain Development Group, Inc. where he served as the Vice President of Acquisitions and Finance through 2006. Mr. Hettinger became a member of the Hettinger Companies in 2007 as the Southern Wyoming Regional Manager and Director of Contract Administration. In 2008, Mr. Hettinger managed oil and gas facility construction projects worth over $90 million dollars for the Hettinger Companies. Mr. Hettinger became a managing member of High Plains Gas, LLC, which was acquired by the Company in connection with the Reorganization Agreement.

Brandon Hargett, Vice President Strategy & Business Development

Mr. Hargett has over 11 years of corporate oil and gas finance and retail investment management experience. Mr Hargett currently oversees business development and acquisition evaluation at the Company. Prior to joining High Plains Gas, Mr. Hargett served as COO of Current Energy where he was instrumental in negotiating and closing the acquisition of the "North & South Fairway" assets of Marathon Oil Corporation (NYSE:MRO) located in the Powder River Basin. Prior to joining Current Energy, Mr Hargett has served as President of Mirus Capital Investment Advisors, which focused on retail investment management. Mr. Hargett graduated with a Bachelors of Science in Health and an M.B.A. from the University of Utah.

Gary Davis, Director

Mr. Davis is the President and Founder of Kahuna Ventures LLC, formed in 1999, a natural gas processing, treating and project-consulting firm, and has well over 32 years in the natural gas space. Kahuna Ventures currently has 40 employees, including 20 engineers and 7 field construction managers or inspectors. Previous to founding Kahuna, Mr. Davis worked at Western Gas Resources, Inc. for over 14 years. Mr. Davis' tenure included holding such positions as Corporate Controller, Sr. Vice President of Engineering & Production, Environmental and Safety, Vice President of Southern Region and Vice President of Engineering & Environmental. During Mr. Davis' time with Western Gas, he assisted in growing a 50-employee company into a major independent mid-stream corporation with over 950 employees and a gross income in excess of $1 billion. Mr. Davis has extensive experience in all project functions including due diligence, site and right of way acquisition, legal, environmental and permitting, safety and operations. Mr. Davis has a B.S. degree from the Colorado School of Mines (CSM) in Chemical and Petroleum Refining Engineering.

Cordell Fonnesbeck, Director

Mr. Fonnesbeck is the owner and founder of his own public accounting firm, Cordell Fonnesbeck, CPA, P.C. since 1991 and has been a member of the American Institute of Certified Public Accountants (AICPA) since 1974. Mr. Fonnesbeck resides in Casper, Wyoming and has been a Certified Public Accountant with over 39 years of public accounting experience. Mr. Fonnesbeck established his Casper, Wyoming CPA firm in 1991 and prior to that was in partnership with three other CPAs. Mr. Fonnesbeck's practice consists mainly of assisting small to medium size businesses and individuals throughout Wyoming and the Intermountain West in the areas of tax compliance, tax planning and accounting services. This practice includes several energy and related industry clients in the Powder River Basin area of Wyoming. From 2005 - 2009, Mr. Fonnesbeck was the accountant for High Plains Gas, LLC, which was the predecessor to High Plains Gas, Inc. Mr. Fonnesbeck serves on the Board of Directors for a Private Charitable Foundation located in Casper. Mr. Fonnesbeck received his bachelor of science degree in business and accounting from Utah State University in 1972.

Alan R. Smith, Director

Mr. Smith began his career in the energy industry in 1966 and has been an exploration geologist, geological consultant, exploration manager, division manager, business development manager (international), and V.P. of international development for such companies as Amoco Production Co., Mountain Fuel Supply Co. (Questar), Lear Petroleum, Davis Oil Co., Inexco Oil Co., and Pennzoil Exploration and Development Co., in both domestic and international capacities. From 1998 to 2003 Mr. Smith was Vice President, International Business Development, for EEX Corporation, where he oversaw the evaluation of exploration and production projects in Asia and Australasia. Mr. Smith has developed and managed many relationships with government oil companies in Indonesia, Brunei and New Zealand. Mr. Smith holds a Bachelor of Science (1966) and Master of Science (1968) in Geology from Brigham Young University and is a Certified Petroleum Geologist with the American Association of Petroleum Geologists and is a Registered Professional Geologist in the State of Wyoming

Director Independence

We have determined that Mr. Gary Davis, Mr. Cordell Fonnesbeck and Mr. Alan R. Smith are independent directors of the Company in accordance with applicable SEC definitions. For purposes of a financial expert of the board we have determined that Mr. Fonnesbeck as a CPA maintains that expertise.

Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 (the "Exchange Act") requires our directors and officers, and persons who own more than ten percent of the Common Stock to file reports of ownership and changes in ownership with the Securities and Exchange Commission ("SEC"). SEC regulations require reporting persons to furnish us with copies of all Section 16(a) forms they file.

Based solely on our review of the copies of the Forms 3, 4 and 5 and amendments thereto furnished to us by the persons required to make such filings during fiscal 2010 and our own records, we believe that all Section 16(a) filing requirements for our officers and directors were complied with on a timely basis.

Corporate Governance

The Company's Corporate Governance Principles and Corporate Code of Conduct (covering all employees and directors), as well as the Certificate of Incorporation and the By-Laws are all available on our website at *www.highplainsgas.com.*

Meetings and Attendance

During the fiscal year ended December 31, 2010, the board of directors met 11 times. In 2010, all directors attended at least 75% of all meetings of the board of directors served after becoming a member of the board.

Relationships Among Directors or Executive Officers

Other than Joseph Hettinger who is the son of Mark D. Hettinger, there are no family relationships among any of our directors or executive officers.

Compensation Committee Interlocks and Insider Participation

No interlocking relationship exists between any member of our board of directors and any member of the board of directors of any other company, nor has such interlocking relationship existed in the past.

Item 11. Executive Compensation

Summary Compensation

The following table summarizes the total compensation awarded to, earned by or paid by us for services rendered by the named executive officers that served during the fiscal years 2010 and 2009.

Name and Principal Position	Year	Salary	Bonus	Option Awards	All Other Compensation	Total
Current Executive Officers:		--	--	--	--	--
Brent M. Cook, Chief Executive Officer	2010	--	--	--	--	--
Mark D. Hettinger, Chairman of the Board of Directors and Chief Operating Officer	2010	--	--	--	--	--
	2009	--	--	--	--	--
Joseph Hettinger, Chief Financial Officer and Director	2010	--	--	--	--	--
	2009	--	--	--	--	--
Brandon Hargett, Vice President Strategy and Business Development	2010	--	--	--	--	--

Compensation Discussion and Analysis

The Company does not have a standing compensation committee. The Company's board of directors as a whole makes the decisions as to employee benefit programs and officer and employee compensation. The primary objectives of the Company's executive compensation programs are to:

- attract, retain and motivate skilled and knowledgeable individuals;
- ensure that compensation is aligned with the Company's corporate strategies and business objectives;
- promote the achievement of key strategic and financial performance measures by linking short-term and long-term cash and equity incentives to the achievement of measurable corporate and individual performance goals; and
- align executives' incentives with the creation of stockholder value.

To achieve these objectives, the Company's board of directors evaluates the Company's executive compensation program with the objective of setting compensation at levels they believe will allow the Company to attract and retain qualified executives. In addition, a portion of each executive's overall compensation is tied to key strategic, financial and operational goals set by the Company's board of directors. The Company also generally provides a portion of the Company's executive compensation in the form of options that vest over time, which the Company believes helps the Company retain the Company's executives and align their interests with those of the Company's stockholders by allowing the executives to participate in the Company's longer term success as reflected in asset growth and stock price appreciation.

Named Executive Officers

The following table identifies the Company's principal executive officer, the Company's principal financial officer and the Company's most highly paid executive officers, who, for purposes of this Compensation Disclosure and Analysis only, are referred to herein as the "Named Executive Officers."

Name	Corporate Office(s)
Brent M. Cook	Chief Executive Officer
Mark D. Hettinger	President and Chief Operating Officer
Joseph Hettinger	Chief Financial Officer
Brandon Hargett	Vice President of Strategy and Business Development

Components of the Company's Executive Compensation Program

The primary elements of the Company's executive compensation program will be base salaries and equity grant incentive awards, although the board of directors has the authority to award cash bonuses, benefits and other forms of compensation as it sees fit. The Company currently does not have any equity plan in place.

The Company does not have any formal or informal policy or target for allocating compensation between short-term and long-term compensation, between cash and non-cash compensation or among the different forms of non-cash compensation. Instead, the Company has determined subjectively on a case-by-case basis the appropriate level and mix of the various compensation components. Similarly, the Company does not rely on benchmarking against the Company's competitors in making compensation related decisions.

Base salaries

Base salaries will be used to recognize the experience, skills, knowledge and responsibilities required of the Company's Named Executive Officers. Base salary, and other components of compensation, may be evaluated by the Company's board of directors for adjustment based on an assessment of the individual's performance and compensation trends in the Company's industry.

Equity Awards

The Company's stock option award program will be the primary vehicle for offering long-term incentives to the Company's executives. To date, the Company has not issued any equity awards. The Company intends the Company's equity awards to executives to generally be made in the form of common stock or warrants. The

Company believes that equity grants in the form of warrants provide the Company's executives with a direct link to the Company's long-term performance, create an ownership culture, and align the interests of the Company's executives and the Company's stockholders.

Cash bonuses

The Company's board of directors has the discretion to award cash bonuses based on the Company's financial performance and individual objectives. The corporate financial performance measures (revenues and profits) will be given the greatest weight in this bonus analysis. The Company has not yet granted any cash bonuses to any named executive officers.

Benefits and other compensation

The Company's Named Executive Officers are permitted to participate in such health care, disability insurance, bonus and other employee benefits plans as may be in effect with the Company from time to time to the extent the executive is eligible under the terms of those plans. As of the date of this Memorandum, with exception to health care, the Company has not implemented any such employee benefit plans.

Executive Compensation Agreements

As discussed above, the Company has agreed to pay the Named Executive Officers an annual salary. Base salary may be increased from time to time with the approval of the board of directors. The following table summarizes the agreed annual salary of each of the Named Executive Officers:

Summary Annual Salary

Name	Annual Salary
Brent Cook	**$175,000**
Mark Hettinger	**$175,000**
Joe Hettinger	**$150,000**
Brandon Hargett	**$80,000**

Grants of Plan-Based Awards Table for Fiscal Year 2010

The Company's 2010 Employee and Consultant Stock Option Plan provides for the issuance of up to 12,000,000 options to purchase common stock. The options may either be qualified or unqualified, but the plan requires that the exercise price reflect then current market price. No options under that plan have been issued. During fiscal 2010, the Company did not grant any equity awards under any equity award plan.

Option Exercises for Fiscal 2010

During fiscal 2010, none of the Named Executive Officers exercised options.

Nonqualified Deferred Compensation

The Company currently offers no defined contribution or other plan that provides for the deferral of compensation on a basis that is not tax-qualified to any of the Company's employees, including the Named Executive Officers.

Compensation of Directors

The Company intends to use a combination of cash and equity-based compensation to attract and retain candidates to serve on the Company's board of directors. The Company will not compensate directors who are also the Company's employees for their service on the Company's board of directors. The Company did not provide any compensation to any member of the Company's Board of Directors, other than as employees, for the fiscal year ended December 31, 2010.

Compensation Committee Interlocks and Insider Participation

The Company does not currently have a standing Compensation Committee. The Company's entire board of directors participated in deliberations concerning executive officer compensation.

Employment, Severance and Change of Control Arrangements

Mark D. Hettinger

Mark D. Hettinger signed an employment agreement with the Company effective January 1, 2011. The agreement provides for employment for a period of one year from the effective date, ending at the close of business on December 31, 2011. The agreement is automatically renewed if neither party provides notice 60 days prior to termination. The agreement states that the Company employs Mr. Hettinger as its Chairman of the Board, and that he reports to the Company's Board of Directors. The agreement established his starting annual base salary at $175,000, subject to reviews and increases at the sole discretion of the Board.

If Mr. Hettinger resigns his employment for good reason, or the Company terminates his employment without cause, he will be entitled to receive all accrued but unpaid salary and benefits through the date of termination plus three months' severance of his base salary. In the event Mr. Hettinger resigns from the Company without good reason, or if the Company terminates his employment with cause, the Company has no liability to him except to pay his base compensation and any accrued benefits through his last day worked, and he will not be entitled to receive severance or other benefits.

Brent M. Cook

Brent M. Cook signed an employment agreement with the Company effective January 1, 2011. The agreement provides for employment for a period of one year from the effective date, ending at the close of business on December 31, 2011. The agreement is automatically renewed if neither party provides notice 60 days prior to termination. The agreement states that the Company employs Mr. Cook as its Chief Executive Officer, and that he reports to the Company's Board of Directors. The agreement established his starting annual base salary at $175,000, subject to reviews and increases at the sole discretion of the Board.

If Mr. Cook resigns his employment for good reason, or the Company terminates his employment without cause, he will be entitled to receive all accrued but unpaid salary and benefits through the date of termination plus three months' severance of his base salary. In the event Mr. Cook resigns from the Company without good reason, or if the Company terminates his employment with cause, the Company has no liability to him except to pay his base compensation and any accrued benefits through his last day worked, and he will not be entitled to receive severance or other benefits.

Joseph Hettinger

Joseph Hettinger signed an employment agreement with the Company effective January 1, 2011. The agreement provides for employment for a period of one year from the effective date, ending at the close of business on December 31, 2011. The agreement is automatically renewed if neither party provides notice 60 days prior to termination. The agreement states that the Company employs Mr. Hettinger as its Chief Financial Officer, and that he reports to the Company's Board of Directors. The agreement established his starting annual base salary at $150,000, subject to reviews and increases at the sole discretion of the Board.

If Mr. Hettinger resigns his employment for good reason, or the Company terminates his employment without cause, he will be entitled to receive all accrued but unpaid salary and benefits through the date of termination plus three months' severance of his base salary. In the event Mr. Hettinger resigns from the Company without good reason, or if the Company terminates his employment with cause, the Company has no liability to him except to pay his base compensation and any accrued benefits through his last day worked, and he will not be entitled to receive severance or other benefits.

Brandon Hargett

Brandon Hargett signed an employment agreement with the Company effective January 1, 2011. The agreement provides for employment for a period of one year from the effective date, ending at the close of business on December 31, 2011. The agreement is automatically renewed if neither party provides notice 60 days prior to termination. The agreement states that the Company employs Mr. Hargett as an employee in business development and that he reports to the Chief Executive Officer. The agreement established his starting annual base salary at $80,000, subject to reviews and increases at the sole discretion of the Board.

If Mr. Hargett resigns his employment for good reason, or the Company terminates his employment without cause, he will be entitled to receive all accrued but unpaid salary and benefits through the date of termination plus three months' severance of his base salary. In the event Mr. Hargett resigns from the Company without good reason, or if the Company terminates his employment with cause, the Company has no liability to him except to pay his base compensation and any accrued benefits through his last day worked, and he will not be entitled to receive severance or other benefits.

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

The following table shows the beneficial ownership of the Company's common stock as of April 15, 2011. The table shows the amount of shares owned by each person known to the Company who will own beneficially more than five percent of the outstanding shares of any class of the Company's stock, based on the number of shares outstanding assuming completion of the reorganization; each of the Company's Directors and Executive Officers; and all of its Directors and Executive Officers as a group.

Name of Person or Group	Number of Shares Beneficially owned[1]	Percent of Shares Beneficially Owned[2]
Mark D. Hettinger, Chief Operating Officer and Director	**47,840,000**	**28.7%**
Joseph Hettinger, Chief Financial Officer and Director	**40,300,000**	**24.2%**
Brent M. Cook, Chief Executive Officer	**22,500,000(3)**	**13.5%**
Brandon Hargett, Vice President of Strategy and Business Development	**22,500,000(3)**	**13.5%**
Gary Davis, Director	**0**	*****
Cordell Fonnesbeck, Director	**0**	*****
Alan R. Smith, Director	**0**	*****
Fletcher International, Ltd.	**10,000,000(4)**	**5.7%**
All Directors and Officers as a Group	**110,640,000**	**66.4%**

* Less than 0.1%

(1) Pursuant to Rule 13d-3 under the Securities Exchange Act of 1934, involving the determination of beneficial owners of securities, a beneficial owner of securities is a person who directly or indirectly, through any contract, arrangement, understanding, relationship or otherwise has, or shares, voting power and/or investment power with respect to the securities, and any person who has the right to acquire beneficial ownership of the security within sixty days through means including the exercise of any option, warrant or conversion of a security.

(2) The percentage of shares owned is based on approximately 166,523,602 shares of common stock outstanding as of April 15, 2011. Also reflects a one for one stock dividend effective December 16, 2010. Where the beneficially owned shares of any individual or group in the following table includes any options, warrants, or other rights to purchase shares, the percentage of shares owned includes such shares as if the right to purchase had been duly exercised.

(3) Reflects 22,500,000 shares held by Current Energy Corporation, of which Mr. Cook and Mr. Hargett may be deemed to be beneficial owners.

(4) Reflects the maximum number of shares issuable to Fletcher International Corporation pursuant to a warrant to purchase up to $5,000,000 in shares issued on March 3, 2011. The warrant exercise price is the lesser of $1.25 per share or the volume weighted average market price for the prior calendar month (with a minimum exercise price of $0.50 per share).

Item 13. Certain Relationships, Related Transactions and Director Independence

We have adopted a written policy for the review and approval of related party transactions which is defined as a sale or purchase of property, supplies or services to or from any director or officer of the company, members of a director's or officer's family, or entities in which any of these persons is a director, officer or owner of 5% or more that that entity's interests. Our policy requires prior approval by both a majority of our Board of Directors and a majority of our disinterested directors who are not employees of the company.

***Indebtedness to Related Parties*.**

Mark Hettinger – During 2010 the Company entered into various loan agreements with Mark Hettinger totaling $4,942,591. The loans are due on demand along with interest at a rate of 15.0% per annum. No payments were made on these notes during 2010 and interest totaling $102,719 has been accrued as of December 31, 2010.

Joe Hettinger – During 2010 the Company entered into various loan agreements with Joe Hettinger totaling $417,194. The loans are due on demand along with interest at a rate of 15.0% per annum. No payments were made on these notes during 2010 and interest totaling $7,080 has been accrued as of December 31, 2010.

Mike Hettinger – During 2010 the Company entered into a loan agreement with Mike Hettinger for $200,000. The loan is due on demand along with interest at a rate of 10.0% per annum. No payments were made on this note during 2010 and interest totaling $1,699 has been accrued as of December 30, 2010.

Mike Hettinger – During 2010, the Company entered into a convertible note agreement with Mike Hettinger totaling $550,000. The convertible note is due on December 31, 2010 along with interest at a rate of 10% per annum. The conversion feature in the convertible note is considered to be a beneficial conversion feature. We have accounted for the beneficial conversion feature in accordance with ASC Topic 470, *Liabilities.* We accounted for a portion of the proceeds, $275,000, from the convertible note which related to the intrinsic value of the beneficial conversion feature by allocating that amount to additional paid in capital. As described in Note 8, the convertible note was converted into 40,000 shares of common stock.

During 2010, the Company entered into a convertible note agreement with an individual totaling $100,000. The convertible note is due on December 31, 2010 along with interest at a rate of 10% per annum. The conversion feature in the convertible note is considered to be a beneficial conversion feature. We have accounted for a portion of the proceeds, $50,000, from the convertible note which related to the intrinsic value of the beneficial conversion feature by allocating that amount to additional paid in capital. As described in Note 8, the convertible note was converted into 10,000 shares of common stock.

Accrued wages and compensation – During 2010 the Company accrued unpaid wages and compensation to various related parties totaling $325,000. The amounts are due on demand and do not include interest. No payments were made on the accrued amounts during 2010.

Principal due to related parties was $5,963,900 and $0 and accrued interest was $111,498 and $0 as of December 31, 2010 and 2009, respectively.

Other transactions

Because of the remote location of the Company's headquarters, the Company periodically utilizes an airplane owned by Mark D. Hettinger for business related travel. Mr. Hettinger is reimbursed all costs associated with utilization of such airplane. For the fiscal year ended December 31, 2010, those expenses totaled $63,200.

On December 31, 2010, Mike Hettinger converted a note payable from the Company for $550,000 into 1,100,000 shares of common stock.

Current Transaction

Brent M. Cook and Brandon Hargett, officers of the Company, are principals of Current Energy Corporation. As described elsewhere in this report, Current received 22,500,000 common shares and will receive $1,500,000 in repayment of a promissory note in connection with the sale to the Company of the Marathon Assets

Item 14. Principal Accounting Fees and Services

Independent Public Accountants

Effective December 9, 2010 we engaged Eide Bailly, LLP ("Eide Bailly")as our independent registered public accounting firm. Our predecessor's independent registered public accounting firm was Chang G. Park, CPA's ("Park"), although Park has not provided services to us.

Fees Billed by Principal Accountants – The following table presents fees for professional services paid to Eide Bailly during the years ended December 31, 2010 and 2009:

	December 31, 2010	**December 31, 2009**
Audit fees	0	0
Tax fees	0	0
Audit related fees	0	0
Total - Eide Bailly	0	0

The following table presents fees for professional services paid to Park during the years ended December 31, 2010 and 2009:

	December 31, 2010	**December 31, 2009**
Audit fees	$ 17,500	$ 8,500
Tax fees	0	0
Audit related fees	0	0
Total - Park	$ 17,500	$ 8,500

Audit Committee Pre-Approval of Services of Principal Accountants

When appointed, the Company's Audit Committee will have the sole authority and responsibility to select, evaluate, determine the compensation of, and, where appropriate, replace the independent auditor. After determining that providing the non-audit services is compatible with maintaining the auditor's independence, the Audit Committee will pre-approve all audits and permitted non-audit services to be performed by the independent auditor, except for *de minimus* amounts. If it is not practical for the Audit Committee will meet to approve fees for permitted non-audit services.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) List of financial statements and schedules.

The following consolidated financial statements of High Plains Gas, Inc. and Subsidiaries are included herein by reference to the pages listed in "Item 8. Financial Statements and Supplementary Data":

Report of Independent Registered Public Accounting Firm

Consolidated Balance Sheets as of December 31, 2010 and 2009

Consolidated Statements of Operations for the years ended December 31, 2010 and 2009

Consolidated Statements of Changes in Shareholders' Equity for the years ended December 31, 2010 and 2009

Consolidated Statements of Cash Flows for the years ended December 31, 2010 and 2009

Notes to Consolidated Financial Statements

(b) List of exhibits: See Exhibit Index immediately preceding exhibits.

ITEM 8. FINANCIAL STATEMENTS.

FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and
Stockholders of High Plains Gas, Inc.
Gillette, Wyoming

We have audited the accompanying consolidated balance sheets of High Plains Gas, Inc. as of December 31, 2010 and 2009, and the related consolidated statements of operations, changes in stockholders' equity, and cash flows for each of the years then ended. High Plains Gas, Inc.'s management is responsible for these financial statements. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits 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 High Plains Gas, Inc. as of December 31, 2010 and 2009, and the results of its operations and its cash flows for each of the years then ended in conformity with accounting principles generally accepted in the United States of America.

Greenwood Village, Colorado
April 15, 2011

HIGH PLAINS GAS, INC.
CONSOLIDATED BALANCE SHEETS
DECEMBER 31, 2010 AND 2009

	2010	2009
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 208,823	$ 45,426
Certificates of deposit	200,000	175,000
Accounts receivable	1,114,335	119,786
Investment in equity securities, at fair value	2,645,108	--
Deferred financing fees	196,238	--
Bond commitment fees	2,469,914	--
Prepaid and other	143,741	25,962
Total current assets	6,978,159	366,174
Oil and Gas Properties-using successful efforts method	42,755,317	3,060,535
Less accumulated depletion, depreciation and amortization	(3,174,836)	(1,897,893)
Oil and Gas Properties-net	39,580,481	1,162,642
Property, Plant and Equipment-net	1,316,307	19,905
Other Assets	125,000	2,022
Total Assets	$ 47,999,948	$ 1,550,743
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 4,416,745	$ 276,688
Accounts payable-related parties	--	30,196
Current portion-term debt	1,661,685	119,131
Current portion - lines of credit	6,352,579	800,000
Total current liabilities	12,431,009	1,226,015
Notes Payable – related parties	6,033,666	--
Debt Obligations – lines of credit, net of current	162,624	317,432
Debt Obligations – term debt, net of current	943,065	--
Commodity derivative	603,742	--
Asset Retirement Obligation	8,229,630	33,046
Total liabilities	28,403,736	1,576,493
Stockholders' Equity:		
Common stock-$.001 par value: 250,000,000 shares authorized; 160,934,202 shares and 0 shares issued and outstanding, respectively	160,934	130,000
Additional paid in capital	25,256,500	181,985
Accumulated income (loss)	(5,821,222)	(337,735)
Total shareholders' equity	19,596,212	(25,750)
Total Liabilities and Stockholders' Equity	$ 47,999,948	$ 1,550,743

See accompanying notes to financial statements

HIGH PLAINS GAS, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 2010 AND 2009

		2010		2009
Revenues:				
Gas and oil revenue	$	2,464,552	$	520,620
Pipeline revenue		110,506		235,689
Other		36,911		87,930
Total Revenue		2,611,969		844,239
Costs and Expenses				
Lease operating expense and production taxes		3,230,426		613,873
General and administrative expense		3,288,816		210,454
Depreciation, depletion and amortization		1,306,617		432,051
Accretion of asset retirement obligation		65,979		2,139
Total Costs and Expenses		7,891,838		1,258,517
Operating (Loss)		(5,279,869)		(414,278)
Other Income (Expense)				
Other income		481,302		9,889
Gain on valuation of equity securities		1,935,234		--
Amortization of bond commitment and financing fees		(291,667)		--
Commodity derivative adjustment		(603,742)		--
Interest (expense)		(1,724,745)		(62,721)
Total Other Income (Expense)		203,618		(52,832)
Net Income (Loss)	$	(5,483,487)	$	(467,110)
Net income (loss) per share	$	(0.04)	$	(0.01)
Weighted average number of common shares outstanding - basic and diluted		132,963,461		65,000,000

See accompanying notes to financial statements

HIGH PLAINS GAS, INC.
CONSOLIDATED STATEMENTS OF CASH FLOW
FOR THE YEARS ENDED DECEMBER 31, 2010 AND 2009

	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (5,483,487)	$ (467,110)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depletion, depreciation and amortization	1,664,263	434,190
Derivative fair value	603,742	--
Stock based compensation	1,282,783	--
Gain on sale of assets	(401,000)	--
Gain on fair value of securities	(1,935,234)	--
Changes in operating assets and liabilities:		
Accounts receivable	(994,549)	(17,333)
Certificate of deposit	--	--
Prepaid and other assets	(117,779)	(6,614)
Payables and accrued liabilities	4,134,101	63,495
Net cash (used in) operating activities	(1,247,160)	6,628
CASH FLOWS FROM INVESTING ACTIVITIES:		
Additions to oil and gas properties	(7,280,160)	(349,896)
Purchase of equipment	(1,302,303)	--
Proceeds from sale of assets	401,000	--
Purchase bond	(350,000)	--
Net cash provided by (used in) investing activities	(8,531,463)	(349,896)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from related party debt	4,905,385	193,986
Proceeds from line of credit	661,148	220,000
Payment on line of credit	(945,945)	(100,102)
Member contributions	678,220	--
Redemptions of members	(134,000)	--
Stock issued for cash	2,680,100	--
Payment of financing fees	(71,075)	--
Proceeds from debt	2,700,000	--
Payment on debt	(531,813)	--
Net cash provided by financing activities	9,942,020	313,884
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	163,397	(29,384)
CASH AND EQUIVALENTS, at beginning of period	45,426	74,810
CASH AND EQUIVALENTS, at end of period	$ 208,823	$ 45,426

See accompanying notes to financial statements

HIGH PLAINS GAS, INC.
CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS'S EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2010 AND 2009

	COMMON STOCK		ADDITIONAL	RETAINED	
	SHARES	PAR VALUE $.001	PAID-IN CAPITAL	EARNINGS (DEFICIT)	TOTAL
Balances, Northern Exploration, Inc,					
Beginning balances	99,720,000	99,720	$ (99,720)	$ --	$ --
Reverse stock split	(99,221,400)	(99,221)	99,221	--	--
Conversion of Loans	12,501,400	12,501	(12,501)	--	--
Subtotal	13,000,000	13,000	(13,000)	--	--
Shares issued in recapitalization	52,000,000	52,000	65,999	129,375	247,374
Shares issued to CEDE	11	--	--	--	--
Stock dividend	65,000,011	65,000	(65,000)	--	--
Contributed Capital	--	--	193,986	--	193,986
Net (loss)	--	--	--	(467,110)	(467,110)
Balances, December 31, 2009	130,000,022	130,000	181,985	(337,735)	(25,750)
Contributed capital	--	--	678,220	--	678,220
Redemption of certain members	--	--	(134,000)	--	(134,000)
Warrants issued - compensation	--	--	228,290	--	228,290
Warrants issued – bond commitment fee	--	--	443,897	--	443,897
Stock issued as bonus with convertible note	10,000	10	6,490	--	6,500
Stock issued for bond commitment fee	800,000	800	519,200	--	520,000
Stock issued for cash	200,000	200	99,900	--	100,100
Stock issued as bonus with convertible note	55,000	55	41,195	--	41,250
Value of beneficial conversion feature of convertible note	--	--	50,000	--	50,000
Stock and warrants issued for cash	800,000	800	399,200		400,000
Stock issued for cash	4,360,000	4,360	2,175,640	--	2,180,000
Stock issued for legal services	80,000	80	57,520	--	57,600
Warrants issued – compensation	--	--	125,739	--	125,739
Detachable warrants issued with debt	--	--	725,765	--	725,765
Stock issued for acquisition of CEP-M	22,500,000	22,500	17,415,000	--	17,437,500
Stock issued to Big Cat Energy Corporation	739,180	739	509,295	--	510,034
Stock issued to American Capital Ventures	250,000	250	172,250	--	172,500
Stock issued as bonus with convertible note	40,000	40	38,360	--	38,400
Value of beneficial conversion feature of convertible note	--	--	275,000	--	275,000
Stock issued for note conversion	1,100,000	1,100	548,900	--	550,000
Warrants issued – compensation	--	--	698,654	--	698,654
Net (loss)	--	--	--	(5,483,487)	(5,483,487)
Balance December 31, 2010	160,934,202	160,934	$ 25,256,500	$ (5,821,222)	$ 19,596,212

See accompanying notes to financial statements.

HIGH PLAINS GAS, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. **<u>ORGANIZATION AND NATURE OF OPERATIONS</u>**:

High Plains Gas, Inc. ("High Plains," "Company," "we," "our," or "us") was originally incorporated in Nevada as Northern Explorations, Ltd. ("Northern Explorations") on November 17, 2004. From its inception, the Company was engaged in the business of exploration of natural resource properties in the United States. After the effective date of its registration statement filed with the Securities and Exchange Commission (February 14, 2006), the Company commenced quotation on the Over-the-Counter Bulletin Board under the symbol "NXPN."

On September 13, 2010 the Company amended its Articles of Incorporation to change its name to High Plains Gas, Inc. We also completed a 1 for 200 reverse split of the common stock and increased the authorized common stock to 250,000,000 shares. In April 2011, we increased our authorized common stock to 350,000,000 shares.

On September 30, 2010 the Company entered into an Operations and Convertible Note Purchase Agreement ("Agreement") with Current Energy Partners Corporation ("CEP"), a Delaware corporation and its wholly owned subsidiary CEP-M Purchase LLC (CEP-M). Under terms of the Agreement, the Company purchased a convertible note from CEP with the proceeds to be used by CEP to acquire a significant resource base and land position from Pennaco Energy, Inc., a wholly owned subsidiary of Marathon Oil Company. On October 31, 2010 the Company entered into an agreement with CEP pursuant to which the Company acquired a 49% interest in CEP-M. On November 19, 2010 the convertible note was converted into a 51% membership interest in CEP-M, giving the Company effective control of 100% of CEP-M.

On October 18, 2010, the Company pursuant to a reorganization agreement with High Plains Gas LLC issued 52,000,000 shares to nine individuals representing 100% of the membership of High Plains Gas, LLC and as a result High Plains Gas, LLC became a wholly owned subsidiary of the Company. Also under the reorganization agreement, shareholders and other parties representing what was Northern Explorations retained approximately 13,000,000 shares of the Company's common stock.

The reorganization has been accounted for as a reverse merger and under the accounting rules for a reverse merger, the historical financial statements and results of operations of High Plains Gas, LLC became those of the Company.

The trading symbol has been changed to "HPGS" to more accurately reflect the Company's new identity.

High Plains is a natural gas and petroleum exploration, development and production company, engaged in locating and developing hydrocarbon resources, primarily distressed and/or orphaned oil and gas projects throughout the Rocky Mountain region. The Company's principal business is the acquisition of leasehold interests in natural gas and petroleum rights and the development of properties subject to these leases. The Company is currently focusing its operational efforts in the Powder River Basin in Wyoming and Montana, targeting coal be methane reserves with prospective acreage potential to the Niobrara Shale, Mowry Shale and Muddy formations.

The Company's operations and plans for expansion are dependent upon continued equity or debt financing.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Basis of Presentation

The consolidated financial statements include High Plains and its wholly owned subsidiaries, High Plains Gas, LLC and CEP-M. All significant intercompany transactions have been eliminated in consolidation.

Use of Estimates

The preparation of the financial statements in conformity with generally accepted accounting principles of the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and 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 may differ from these estimates under different assumptions or conditions. The Company's financial statements are based on a number of significant estimates, including (1) oil and gas reserve quantities; (2) depletion, depreciation and amortization; (3) assigning fair value and allocating purchase price in connection with business combinations; (4) valuation of commodity derivative instruments; (5) asset retirement obligations; (6) valuation of share-based payments; (7) income taxes, and (8) cash flow estimates used in impairment tests of long-lived assets.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand, amounts held in banks and highly liquid investments purchased with an original maturity of three months or less.

Business Segment Information

The Company has evaluated how it is organized and managed and has identified only one operating segment, which is the exploration and production of natural gas, natural gas liquids and crude oil. The Company considers its gathering and marketing functions as ancillary to its oil and gas producing activities. All of the Company's operations and assets are located in the United States, and all of its revenues are attributable to United States customers.

Concentration of Credit Risk

The Company's cash equivalents are exposed to concentrations of credit risk. The Company manages and controls this risk by placing these funds with major financial institutions.

The Company's accounts receivable result from (1) oil and natural gas sales to oil and intrastate pipeline companies and (2) billings to joint working interest partners in properties operated by the Company. The Company's trade and accrued production receivables are disbursed among various customers and purchasers and most of the Company's significant purchasers are large companies with solid credit ratings. If customers are considered a credit risk, letters of credit are the primary security obtained to support the extension of credit however no letters of credit were held at either December 31, 2010 or 2009. For most joint working interest partners, the Company may have the right of offset against related oil and natural gas revenues. The joint interest working partner receivables are not collateralized and to date the Company has had minimal bad debts. No allowance for uncollectible receivables has been recorded at December 31, 2010 and 2009.

Significant Customers

The following table provides the percentage of revenue derived from oil and natural gas sales to the Company's top three customers (the customers in each year are not necessarily the same from year to year):

	Years ended December 31,	
	2010	2009
Customer A	50%	100%
Customer B	46%	%
Customer C	4%	%

Oil and Natural Gas Properties

High Plains follows the successful efforts method of accounting for its investments in oil and natural gas properties. The Company uses the successful efforts method of accounting for oil and natural gas producing activities. Costs to acquire mineral interests in oil and gas properties, to drill and equip exploratory wells that find proved reserves, to drill and equip development wells and related asset retirement costs are capitalized. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs, and costs of carrying and retaining unproved properties are expensed.

The unit-of-production method of depreciation, depletion, and amortization of oil and gas properties under the successful efforts method of accounting is applied pursuant to the simple multiplication of units produced by the costs per unit on a field by field basis. Leasehold cost per unit is calculated by dividing the total cost by the estimated total proved oil and gas reserves associated with that field. Well cost per unit is calculated by dividing the total cost by the estimated total proved developed oil and gas reserves associated with that field. The volumes or units produced and asset costs are known and while the proved reserves have a high probability of recoverability, they are based on estimates that are subject to some variability. Depletion expense was $1,306,617 and $432,051 during 2010 and 2009, respectively.

We test for impairment of our properties based on estimates of proved reserves. Proved oil and gas properties are reviewed for impairment whenever events or circumstances indicate that the carrying amount may not be recoverable. We estimate the future undiscounted cash flows of the affected properties to judge the recoverability of the carrying amounts. Initially this analysis is based on proved reserves. However, when we believe that a property contains oil and gas reserves that do not meet the defined parameters of proved reserves, an appropriately risk adjusted amount of these reserves may be included in the impairment evaluation. These reserves are subject to much greater risk of ultimate recovery. An asset would be impaired if the undiscounted cash flows were less than its carrying value. Impairments are measured by the amount by which the carrying value exceeds its fair value.

Impairment analysis is performed on an ongoing basis. In addition to using estimates of oil and gas reserve volumes in conducting impairment analysis, it is also necessary to estimate future oil and gas prices and costs, considering all available evidence at the date of review. The impairment evaluation triggers include a significant long-term decrease in current and projected prices or reserve volumes, an accumulation of project costs significantly in excess of the amount originally expected and historical and current negative operating losses. Although we evaluate future oil and gas prices as part of the impairment analysis, we do not view short-term decreases in prices, even if significant, as impairment triggering events.

Unproved property costs not subject to amortization consist primarily of leasehold costs related to unproved areas. Costs are transferred into the amortization base on an ongoing basis as the properties are evaluated and proved reserves are established or impairment is determined. Costs of dry holes are expensed immediately upon determination that the well is unsuccessful. The Company will continue to evaluate these properties and costs which will be transferred into the amortization base as the undeveloped areas are tested. The Company did not transfer any unproved costs to the amortization base during 2010 or 2009.

During 2010 and 2009, there was no impairment expense related to oil and natural gas properties.

Aggregate Capitalized Costs

Aggregate capitalized costs relating to the Company's crude oil and natural gas producing activities, including asset retirement costs and related accumulated depreciation, depletion and amortization are as follows:

	Year Ended December 31, 2010	2009
Proved oil and gas properties	$ 42,755,317	$ 3,060,535
Accumulated DD&A	(3,174,836)	(1,897,893)
Net capitalized costs	$ 39,580,482	$ 1,162,642

Costs incurred in Oil and Gas Activities

Costs incurred in connection with the Company's crude oil and natural gas acquisition, exploration and development activities for each of the years are shown below:

	Year Ended December 31, 2010	2009
Unproved property costs	$ -	$ -
Exploration costs	-	-
Acquisition costs	-	321,203
Development costs	-	354,251
ARO Costs	-	-
Total operations	$ -	$ 675,454
Asset retirement obligation (non-cash)	$ -	$ -

Equipment and Depreciation

Property and equipment is stated at cost and is depreciated using the straight-line method over estimated useful lives of 5 to 10 years.

	2010	2009
Transportation and vehicles	$ 607,422	$ 24,796
Equipment and other	582,698	23,625
Computers and software	155,862	--
	1,345,982	48,421
Less Depreciation	(29,674)	(14,258)
	$ 1,316,308	$ 34,163

Depreciation expense was $29,674 and $6,833 during 2010 and 2009, respectively.

Bond Commitment Fees

Fees paid to secure commitments from lenders and to secure bonding arrangements with the State and other local government entities are capitalized and amortized on a straight-line basis over the expected term of the arrangement. Fees paid during 2010 to shareholders totaled $2,963,897 and amortization of these fees is over a 12-month period. Amortization during 2010 totaled $493,983.

Deferred Financing Fees

Deferred loan costs are amortized over the estimated lives of the related obligations or, in certain circumstances, accelerated if the obligation is refinanced. Amortization is calculated using the straight-line method which approximates the effective interest method.

Derivative Financial Instruments

The Company enters into derivative contracts, primarily swap contracts, to hedge future natural gas production in order to mitigate the risk of market price fluctuations. All derivative instruments are recorded on the balance sheet at fair value. All of the Company's derivative counterparties are financial institutions. If the derivative does not qualify as a hedge or is not designated as a hedge, the gain or loss on the derivative is recognized currently in earnings as a component of financing costs and other. There are no derivative contracts entered into during 2010 that qualify as hedges. There were no derivative contracts in place during 2009.

Off-Balance Sheet Arrangements

From time-to-time, the Company enters into off-balance sheet arrangements and transactions that can give rise to off-balance sheet obligations. As of December 31, 2010 the off-balance sheet arrangements that the Company had entered into include undrawn letters of credit, operating lease agreements, gathering, compression, processing and water disposal agreements and gas transportation commitments. The Company does not believe that these arrangements are reasonably likely to materially affect its liquidity or availability of, or requirements for, capital resources.

Revenue Recognition and Gas Imbalances

Revenues from the sale of natural gas and crude oil are recognized when the project is delivered at a fixed or determinable price, title as transferred, collectability is reasonably assured and evidenced by a contract. This occurs when oil or gas has been delivered to a pipeline or a tank lifting has occurred. The Company may have an interest with other producers in certain properties, in which case the Company uses the sales method to account for gas imbalances. Under this method, revenue is recorded on the basis of gas actually sold by the Company. In addition, the Company records revenue for its share of gas sold by other owners that cannot be volumetrically balanced in the future due to insufficient remaining reserves. The Company also reduces revenue for other owners' gas sold by the Company that cannot be volumetrically balanced in the future due to insufficient remaining reserves. The Company's remaining over- and under-produced gas balancing positions are considered in the Company's proved oil and gas reserves. Gas imbalances at December 31, 2010 and 2009 were not significant.

Asset Retirement Obligation

The Company follows the provisions of ASC 410, *Asset Retirement and Environmental Obligations (ARO)*. The estimated fair value of the future costs associated with dismantlement, abandonment and restoration of oil and gas properties are recorded when incurred, generally upon acquisition or completion of a well. The net estimated costs are discounted to present values using a risk adjusted rate over the estimated economic life of the oil and gas properties. Such costs are capitalized as part of the related asset. The asset is depleted on the units-of-production method. The associated liability is classified in other long-term liabilities in the accompanying balance sheet. The liability is periodically adjusted to reflect (1) new liabilities incurred, (2) liabilities settled during the period, (3) accretion expense, and (4) revisions to estimated future cash flow requirements. The accretion expense is recorded as a component of depreciation, depletion and amortization expense in the accompanying statements of operations.

Income Taxes

Deferred income tax assets and liabilities are recognized for the future income tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective income tax bases. Deferred income tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred income tax assets and liabilities of a change in income tax rates is recognized in income in the period that includes the enactment date. The measurement of deferred income tax assets is reduced, if necessary, by a valuation allowance if management believes that it is more likely than not that some portion or all of the net deferred tax assets will not be fully realized on future income tax returns. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, available taxes in carryback periods, projected future taxable income and tax planning strategies in making this assessment.

In June 2006, the FASB issued an interpretation related to the existing accounting for income tax guidance regarding how tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under this guidance, the Company may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement.

The Company has analyzed filing positions in all of the federal and state jurisdictions where it is required to file income tax returns, as well as all open tax years in these jurisdictions. No uncertain tax positions have been identified as of December 31, 2010 and 2009.

The Company is no longer subject to U.S. federal income tax examinations by the Internal Revenue Service for tax years before 2007 and for state and local tax authorities for years before 2006.

Risks and Uncertainties

Historically, oil and gas prices have experienced significant fluctuations and have been particularly volatile in recent years. Price fluctuations can result from variations in weather, levels of regional or national production and demand, availability of transportation capacity to other regions of the country and various other factors. Increases or decreases in prices received could have a significant impact on future results.

Environmental

The Company is subject to extensive federal, state and local environmental laws and regulations. These laws and regulations, which regularly change, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a non-capital nature are recorded when environmental assessment and/or remediation is probable and the costs can be reasonably estimated. Such liabilities are generally recorded at their undiscounted amounts unless the amount and timing of payments is fixed or reliably determinable. The Company believes that it is in material compliance with existing laws and regulations.

Earnings (Loss) Per Share

Basic earnings (loss) per share is computed by dividing earnings (loss) attributed to common stock by the weighted average number of common shares outstanding during the reporting period. Contingently issuable shares (unvested restricted stock) are included in the computation of basic net income (loss) per share when the related conditions are satisfied. Diluted earnings (loss) per share is computed using the weighted average number of common shares outstanding including all and potentially dilutive securities (unvested restricted stock and unexercised stock options) outstanding during the period. In the event of a net loss, no potential common shares are included in the calculation of shares outstanding as their inclusion would be anti-dilutive.

As of December 31 2010 and 2009 the Company had shares of common stock outstanding and warrants for the purchase of shares. The warrants were excluded from the calculation of diluted earnings per share for both years, due to the fact that they were anti-dilutive.

Other Comprehensive Income

The Company does not have any material items of other comprehensive income for the years ended December 31, 2010 and 2009. Therefore, total comprehensive income (loss) is the same as net income (loss) for these periods.

Stock-Based Compensation

Stock-based compensation is measured at the grant date based on the value of the awards and is recognized on a straight-line basis over the requisite service period (usually the vesting period). The Company estimates forfeitures in calculating the cost related to stock-based compensation as opposed to recognizing these forfeitures and the corresponding reduction in expense as they occur. Compensation expense is then adjusted based on the actual number of awards for which the requisite service period is rendered. A market condition is not considered to be a vesting condition with respect to compensation expense. Therefore, an award is not deemed to be forfeited solely because a market condition is not satisfied.

Recently Issued Accounting Standards

In December 2008, the Securities and Exchange Commission ("SEC") revised its requirements for oil and gas reserves estimation and disclosures and related definitions to align them with current practices and changes in technology. In January 2010, the Financial Accounting Standards Board ("FASB") aligned the current oil and gas reserve estimation and disclosure requirements with those of the SEC. Among other things, the SEC and FASB amendments replace the single-day, year-end pricing assumption with a twelve-month average pricing assumption with respect to reserve calculations, revise certain definitions and allow the use of certain technologies to establish reserves. The updated requirements are to be applied prospectively as a change in accounting principle that is inseparable from a change in accounting estimate and are effective for entities with annual reporting periods ending on or after December 31, 2009. Thus, as of December 31, 2009, the Company changed its method of determining the quantities of oil and gas reserves which impacted the amount recorded for depreciation, depletion and amortization and the impairment evaluation for oil and gas properties. Under the new rules, the Company prepared its oil and gas reserve estimates as of December 31, 2009 using the average, first-day-of-the-month price during the 12-month period ending December 31, 2009. The adoption of the new rules was considered a change in accounting principle inseparable from a change in accounting estimate. The Company does not believe that provisions of the new guidance, other than pricing, significantly impacted the reserve estimates or consolidated financial statements. The Company does not believe that it is practicable to estimate the effect of applying the new rules on net loss, loss per share or the amount recorded for depreciation, depletion and amortization and the impairment evaluation for the year ended December 31, 2009.

In June 2009, the FASB issued Accounting Standards Update ("ASU") 2009-01, Generally Accepted Accounting Principles. ASU 2009-01 established the FASB Accounting Standards Codification ("Codification") which became the source of authoritative accounting principles recognized by the FASB to be applied to nongovernmental entities. On the effective date, the Codification superseded all then-existing non-SEC accounting and reporting standards. ASU 2009-01 was effective for interim or annual periods ending after September 30, 2009. We adopted ASU 2009-01 for the interim period ended September 30, 2009 and adoption had no impact on our operating results, financial position or cash flows.

In August 2009, the FASB issued ASU 2009-05, Fair Value Measurements and Disclosures, which provides guidance on the fair value measurement of liabilities. The update also provides clarification for circumstances in which a quoted price in an active market for the identical liability is not available. ASU 2009-05 was effective for interim and annual periods beginning after August 26, 2009. We adopted this provision for the year ended December 31, 2009 and adoption had no impact on our operating results, financial position or cash flows.

In January 2010, guidance for fair value measurements and disclosure was updated to require additional disclosures related to transfers in and out of level 1 and 2 fair value measurements and enhanced detail in the level 3 reconciliation. The guidance was amended to clarify the level of disaggregation required for assets and liabilities and the disclosures required for inputs and valuation techniques used to measure the fair value of assets and liabilities that fall in either level 2 or level 3. The updated guidance was effective for the Company’s year beginning January 1, 2010, with the exception of the level 3 disaggregation which will be effective for the Company’s first reporting period beginning January 1, 2011. The adoption had no impact on the Company’s consolidated financial position, results of operations or cash flows.

We have reviewed all recently issued, but not yet effective, accounting pronouncements and do not believe the future adoption of any such pronouncements may be expected to cause a material impact on our financial condition or the results of our operations.

3. **ACQUISITIONS AND SALES OF PROPERTIES:**

Grams and Mills acquisition:

During April 2010, High Plains purchased oil and gas leases along with personal property in 45 producing methane wells and mineral interests (the Grams and Mills gas fields located in Campbell County, Wyoming) from an unrelated third party for $625,000. The Company paid $150,000 in cash on the closing date and the remaining balance of $475,000 is financed through the seller. These properties are adjacent to fields already owned and operated by the Company, and are subject to the terms and conditions of record regarding overriding royalties and other interests. The seller also reserved a one-third interest in all minerals below the Fort Union Oil Formation or 3,000 feet below the surface, whichever is deeper. The seller also retained its ownership interest in an 8” pipeline that crosses in part the properties being transferred.

Marathon Oil acquisition:

During November 2010, the Company purchased all of the North and South Fairway gas fields from Pennaco Energy, a subsidiary of Marathon Oil, which included gas leases along with personal property in 1,614 producing or idled methane wells (located in Campbell, Johnson and Sheridan Counties, Wyoming). The Company paid an adjusted purchase price of $30,654,813 for these assets. The gas fields included in this sale are located in the following Wyoming Counties: Campbell, Johnson, and Sheridan. The net leased acreage for the North and South Fairway assets is approximately 133,000 acres.

The Marathon Oil asset acquisition qualifies as a business combination, and therefore, the Company was required to estimate the fair value of the assets acquired and liabilities assumed as of the acquisition date to record the acquisition. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

The fair value of the acquired properties was determined based upon numerous inputs, many of which were unobservable (which are defined as Level 3 inputs). The significant inputs used in estimating the fair value were: (1) NYMEX natural gas futures prices (observable), (2) projections of the estimated quantities of natural gas reserves, (3) projections regarding rates and timing of production, (4) projections regarding amounts and timing of future development and abandonment costs, (5) projections regarding the amounts and timing of operating costs and property taxes, (6) estimated risk adjusted discount rates and (7) estimated inflation rates. The fair value of the acquisition was assigned to the assets acquired and liabilities assumed as follows: $8.3 million to proved properties, $11.9 million to unevaluated properties, and $10.4 million to operating equipment. Because the estimated fair value and purchase price were equivalent, the Company did not record goodwill or a gain related to the acquisition.

Alpha sales:

During 2009, the Company sold the gas interest in the CH Davis #1 well for $25,000.

During 2010, the Company received cash of $401,271 resulting from the conveyance of all future rights to the four Eagle Butte wells and the conveyance of all future rights to the CH Davis #1 well.

4. **HEDGING AND DERIVATIVE FINANCIAL INSTRUMENTS:**

The Company utilizes swap contracts to hedge the effect of price changes on a portion of its future natural gas production. The objective of the Company's hedging activities and the use of derivative financial instruments is to achieve more predictable cash flows. While the use of these derivative instruments limits the downside risk of adverse price movements, they also may limit future revenues from favorable price movements.

The use of derivatives involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. The Company's derivative contracts are with multiple counterparties to minimize exposure to any individual counterparty. The Company generally has netting arrangements with the counterparties that provide for the offset of payables against receivables from separate derivative arrangements with that counterparty in the event of contract termination. The derivative contracts may be terminated by a non-defaulting party in the event of default by one of the parties to the agreement. The Company is not required to post collateral when the Company is in a derivative liability position.

As of December 31, 2010, the Company had entered into swap agreements related to its natural gas production as summarized below. Location and quality differentials attributable to the Company's properties are not included in the following prices. The agreements provide for monthly settlement based on the differential between the agreement price and the actual CIG Rocky Mountains price.

5. **RELATED PARTY TRANSACTIONS**:

2009: The Company reimbursed officers for the purchase of fixed asset additions and other business expenses totaling $228,833. As of December 31, 2009, a total of $473 was owed to an officer.

2010: The Company reimbursed officers for the purchase of fixed asset additions and other business expenses totaling $229,627. As of December 31, 2010, a total of $89,188 was owed to a related entity.

The Company transacts business with a shareholder for purchase of drilling tools and performance of contract-based accounting services. The 2010 services totaled $155,520 and had not been paid as of December 31, 2010.

Two officers paid loan origination fees on behalf of the Company totaling $71,075 during 2010.

Two officers have provided personal guarantees on the Amegy Line of Credit. The Company has valued this guarantee at $2,193,897.

See Note 12 for details of related party debt instruments.

6. INVESTMENT IN EQUITY SECURITIES

On December 8, 2010, the Company signed a definitive Stock Purchase Agreement (the "Purchase Agreement") with Big Cat Energy Corporation ("Big Cat") to purchase 20,000,000 shares of Big Cat's restricted common stock, or approximately 31.3% of the projected issued and outstanding shares. The fair value of the shares was $.09 per share as of the date of transaction, or $1,800,000. The Company also received 10,000,000 warrants that are exercisable for 5 years at a price of $0.15 that were valued at $654,430 at the date of transaction. The purchase price consisted of a combination of $200,000 cash and 739,180 restricted common shares of the Company valued at $510,034 for a total value expended of $710,034.

As allowed by ASC 825-10, the Company has elected to follow the fair value option for reporting the securities received from Big Cat because the Company believes this accounting treatment represents a more realistic measure of value that may be realized by the Company should they dispose of the securities on the open market. The Company has elected the fair value option for both the common stock and the warrants. The effect of this election is a gain of $1,744,396, calculated as the difference between the fair value of securities received ($1,800,000 and $654,270) and the value expended ($710,034) for an initial gain recognized in the income statement of $1,744,396.

As of December 31, 2010 the fair value of the securities remains at $.09 per share, or $1,800,000. The fair value of the warrants has increased to $845,108 and the increase of $190,838 has been recognized in the income statement. Total gain recognized for 2010 due to the election of fair value accounting is $1,935,234.

7. CERTIFICATES OF DEPOSIT

The Company maintains certificates of deposits that have been established for the purpose of assuring maintenance and administration of a performance bond which secures certain plugging and abandonment obligations assumed by the Company on its federal leases. At December 31, 2010 and 2009, the outstanding amount totaled $200,000 and $175,000, respectively.

8. SHAREHOLDER EQUITY:

As discussed in Note 1, the reorganization has been accounted for as a reverse merger, and thus the equity structure of the predecessor entity becomes part of the equity structure of High Plains Gas, LLC, wholly owned subsidiary of High Plains Gas, Inc., and effectively the surviving entity.

Effectively, during 2010, the predecessor entity completed a 1 for 200 reverse split of the issued and outstanding common shares, $.001 par value.

Effectively during 2010, the predecessor entity issued 52,000,000 common shares to nine individuals representing 100% of the membership of High Plains Gas, LLC and, as a result, High Plains Gas, LLC became a wholly owned subsidiary of High Plains Gas, Inc.

During 2010, the Company issued a stock dividend of 1 for 1 share of common stock then outstanding. A total of 65,000,011 shares were issued.

During 2009, member contributions in High Plains LLC totaled $193,986.

On January 1, 2010, five members of High Plains LLC were bought out and their shares redeemed. The members collectively held 50 units for 47.5% ownership. High Plains LLC gave up several oil and gas leases and cash totaling $134,000. The leases had no recorded value as they were undeveloped, unproved and had not been evaluated. No reserves were assigned to the leases in the 2009 reserve study.

On January 1, 2010, member contributions in High Plains Gas, LLC totaled $678,220.

During 2010, warrants were issued as compensation and valued at $1,052,683. Warrants were also issued in payment for bond commitment fees and valued at $443,897.

A promissory note was converted into 55,000 common shares valued at $41,250.

Common shares totaling 800,000 shares were issued in payment of bond commitment fees and valued at $520,000.

During 2010, a total of 330,000 shares were issued in payment for various corporate services valued at $230,100.

As discussed in Note 6, 739,180 common shares were issued to Big Cat Energy Corporation at a value of $510,034.

Warrants were issued with corporate debt and valued at $725,765.

Common shares totaling 4,460,000 were issued for cash of $2,680,100.

On November 24, 2010, the Company purchased the remaining 49% of CEP-M Purchase by issuing 22,500,000 shares of restricted common stock at $0.775 per shares and giving Current Energy Partners a note for $1,500,000.

On December 31, 2010, Mike Hettinger, converted a note payable from the Company for $550,000 into 1,100,000 shares of restricted common stock. The conversion included a beneficial conversion feature valued at $275,000 and 40,000 shares of common stock valued at $38,400.

	2010
Expected warrant term - years	2.5 to 5 years
Risk-free interest rate	.42 to 2.01%
Dividend Yield	0
Volatility	106%
Shares granted	4,136,420
Exercise Price	0.50
Weighted Average remaining term	4.88

	Number of Shares	Weighted Avg Exercise Price	Weighted Avg Remaining Contractual Term	Aggregate Fair Value
Warrants outstanding - January 1, 2010				
Granted during period	4,136,420	$ 0.50	$ 4.88	$2,410,594.43
Exercised during period				
Forfeited during period				
Expired during period				
Warrants outstanding - December 31, 2010	4,136,420	$ 0.50	$ 4.88	$2,410,594.43

The above private offerings were made in reliance on an exemption from registration in the United States under Section 4(2) and/or Regulation D of the United States Securities Act of 1933, as amended.

9. LETTERS OF CREDIT

During 2010, the Company entered into a line of credit agreement with First National Bank of Gillette on November 12, 2010 to provide letters of credit to various agencies and entities for the bonding required to operate the Company's methane wells. These letters of credit total $7,839,358 and any outstanding balances carry an interest rate of 1% over the U.S. Bank Denver Prime Rate (effective rate was 4.25% as of December 31, 2010). Any outstanding amounts and related interest are due on demand. The agreement is secured by the right of setoff against corporate depository account balances, a mortgage on certain real property, all improvements and equipment on certain well sites and including rights to future production, assignment of a life insurance policy on the Chief Operating Officer as well as personal guarantees of certain shareholders. There were no amounts outstanding on this agreement as of December 31, 2010.

10. DEBT FINANCING – LINES OF CREDIT

On October 12, 2006, the Company entered into an agreement with First Interstate Bank for a line of credit of up to $800,000 with a maturity date of October 12, 2009. The line of credit is secured by assignments to oil and gas production, and all inventory and account receivable and equipment. On October 22, 2008 the agreement was modified and with a new interest rate of 9.25% and new maturity date of December 7, 2009. On December 7, 2009 the agreement was modified to reflect a new interest rate of 6.0% per annum and a new maturity date of October 12, 2010. The line of credit was fully paid-off and retired in January 2010.

On January 20, 2010, the Company entered into an agreement with U.S. Bank for a line of credit of up to $200,000 with a maturity date of October 31, 2010. The line of credit carries an interest rate of 4.95% per annum and is secured by assignments to oil and gas production, and all inventory and account receivable and equipment. As of December 31, 2010 the outstanding principal balance was $125,000.

On November 19, 2010, the Company (through its wholly owned subsidiary CEP-M Purchase LLC) entered into a letter of credit facility with Amegy Bank National Association ("Amegy") for a revolving line of credit of up to $75,000,000. The facility is to be used to finance up to 60% of the Company's oil and gas acquisitions, subject to approval by Amegy. The interest rate is based on LIBOR, the amount of the credit facility in use and other factors to determine the prevailing rate on outstanding principal balances (effective rate of 6.25% as of December 31, 2010). Outstanding principal balances and any related accrued interest is due on September 17, 2013 subject to mandatory prepayment terms per the agreement. The credit facility is secured by all assets of CEP-M Purchase LLC, a mortgage on all proved reserves of specific wells. As of December 31, 2010 the outstanding principal balance was $6,000,000.

The credit facility is subject to restrictive covenants and as of December 31, 2010, the Company is not in compliance with certain of the covenants. This condition has caused the reclassification of the outstanding balance to be presented as a current liability.

On November 29, 2010, the Company entered into an agreement with First National Bank of Gillette for a line of credit of up to $461,148 to be used for the purchase of corporate vehicles. The line of credit carries an interest rate of 6% interest rate is secured by the right of offset against corporate depository account balances. Terms include the requirement of a monthly payment of $20,400 with any outstanding principal balance and accrued interest due on November 30, 2012. As of December 31, 2010 the outstanding principal balance was $390,202.

	2010	**2009**
Total outstanding principal	$ 6,515,203	$ 800,000
Current portion	6,352,579	800,000
Long-term portion of lines of credit	$ 162,624	$ --

Outstanding balances are due:	
2011	$ 6,352,579
2012	162,624
2013	--
	$ 6,515,203

11. DEBT FINANCING – TERM DEBT

On November 7, 2007, the Company entered in a term loan agreement with First Interstate Bank of $653,250 with a maturity date of July 7, 2013. Payments are due monthly of $12,000 which include interest at 8.25% per annum. The agreement is secured by production and certain oil and gas assets. On May 13, 2008, the agreement was modified to reflect a new interest rate of 6.5% per annum. The loan was fully paid-off and retired in January 2010.

On January 20, 2010, the Company entered into a term loan agreement with U.S. Bank of $1,200,000 with a maturity date of January 20, 2013. Payments are due monthly of $16,935 which include interest at 4.95% per annum. The agreement is secured by the right of offset against corporate depository accounts and is guaranteed by certain shareholders. As of December 31, 2010 the outstanding principal balance was $1,067,225.

On March 11, 2010, the Company entered into a term loan agreement with Ford Motor Credit of $42,820 with a maturity date of March 31, 2015. Payments are due monthly of $871 which include interest at 7.99% per annum. The agreement is secured by a corporate vehicle. As of December 31, 2010 the outstanding principal balance is $37,525.

On November 23, 2010, the Company entered into a term loan agreement with CEP-M with a maturity date of January 31, 2012. The note does not bear interest and is unsecured. As of December 31, 2010 the outstanding principal balances is $1,500,000.

	2010	2009
Total outstanding principal	$ 2,604,750	$ 436,563
Current portion	1,661,685	191,131
Long-term portion of term debt	$ 943,065	$ 317,432
Outstanding balances are due:		
2011	$ 1,661,685	
2012	170,122	
2013	760,740	
2014	9,830	
2015	2,373	
	$ 2,604,750	

12. DEBT FINANCING – RELATED PARTY DEBT

Mark Hettinger – During 2010 the Company entered into various loan agreements with Mark Hettinger totaling $4,942,591. The loans are due on demand along with interest at a rate of 15.0% per annum. No payments were made on these notes during 2010 and interest totaling $102,719 has been accrued as of December 31, 2010.

Joe Hettinger – During 2010 the Company entered into various loan agreements with Joe Hettinger totaling $417,194. The loans are due on demand along with interest at a rate of 15.0% per annum. No payments were made on these notes during 2010 and interest totaling $7,080 has been accrued as of December 31, 2010.

Mike Hettinger – During 2010 the Company entered into a loan agreement with Mike Hettinger for $200,000. The loan is due on demand along with interest at a rate of 10.0% per annum. No payments were made on this note during 2010 and interest totaling $1,699 has been accrued as of December 30, 2010.

Mike Hettinger – During 2010, the Company entered into a convertible note agreement with Mike Hettinger totaling $550,000. The convertible note is due on December 31, 2010 along with interest at a rate of 10% per annum. The conversion feature in the convertible note is considered to be a beneficial conversion feature. We have accounted for the beneficial conversion feature in accordance with ASC Topic 470, *Liabilities.* We accounted for a portion of the proceeds, $275,000, from the convertible note which related to the intrinsic value of the beneficial conversion feature by allocating that amount to additional paid in capital. As described in Note 8, the convertible note was converted into 40,000 shares of common stock.

During 2010, the Company entered into a convertible note agreement with an individual totaling $100,000. The convertible note is due on December 31, 2010 along with interest at a rate of 10% per annum. The conversion feature in the convertible note is considered to be a beneficial conversion feature. We have accounted for a portion of the proceeds, $50,000, from the convertible note which related to the intrinsic value of the beneficial conversion feature by allocating that amount to additional paid in capital. As described in Note 8, the convertible note was converted into 10,000 shares of common stock.

Accrued wages and compensation – During 2010 the Company accrued unpaid wages and compensation to various related parties totaling $325,000. The amounts are due on demand and do not include interest. No payments were made on the accrued amounts during 2010.

Principal due to related parties was $5,963,900 and $0 and accrued interest was $111,498 and $0 as of December 31, 2010 and 2009, respectively.

13. INCOME TAXES

Deferred tax assets (liabilities) are comprised of the following:

	December 31,	
	2010 *	2009 *
Current deferred tax assets:		
Fair Value Securities	$ (677,332)	
Noncurrent deferred tax assets:		
Oil and gas property and equipment	$ 566,429	
Stock based compensation	$ 368,439	
Net operating loss	$ 1,873,894	
Total deferred tax assets	$ 2,131,428	
Valuation allowance	$ (2,131,428)	
	$ –	

A reconciliation of our effective tax rate to the federal statutory tax rate of 35% is as follows:

	December 31,	
	2010 *	2009 *
Expected benefit at federal statutory rate	(35%)	
State taxes net of federal benefit	--	
Permanent differences	--	
Change in valuation allowance	35%	
	–	

*Until October 18, 2010, the Company was operated as a Limited Liability Company. As such, all income and losses were reported directly by the members and thus there is no corporate tax effect until October 18, 2010.

The federal net operating loss (NOL) carry forward of approximately $8,590,000 as of December 31, 2010 begins to expire in 2030. Internal Revenue Code Section 382 places a limitation on the amount of taxable income which can be offset by NOL carryforwards after a change in control (generally greater than 50% change in ownership) of a loss corporation. Generally, after a change in control, a loss corporation cannot deduct NOL carryforwards in excess of the Section 382 limitation. Due to these “change in ownership” provisions, utilization of NOL carryforwards may be subject to an annual limitation regarding their utilization against taxable income in future periods. We have not performed a Section 382 analysis. However, if performed, Section 382 may be found to limit potential future utilization of our NOL carryforwards.

We have established a full valuation allowance against the deferred tax assets because, based on the weight of available evidence including our continued operating losses, it is more likely than not that all of the deferred tax assets will not be realized. Because of the full valuation allowance, no income tax expense or benefit is reflected on the statement of operations.

14. FAIR VALUE MEASUREMENT AND DISCLOSURE

The Company has adopted ASC 820, *Fair Market Measurement and Disclosures* including the application of the statement to non-recurring, non-financial assets and liabilities. The adoption of ASC 820 did not have a material impact on the Company's fair value measurements. ASC 820 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants at the measurement date. ASC 820 establishes a fair value hierarchy, which prioritizes the inputs used in measuring fair value into three broad levels as follows:

Level 1- Quoted prices in active markets for identical assets or liabilities.
Level 2- Inputs, other than the quoted prices in active markets that are observable either directly or indirectly.
Level 3- Unobservable inputs based on the Company's own assumptions,

The Company has elected the fair value option for reporting its investment in securities available for sale, because the Company believes this option presents a more realistic measure of value that may be realized by the Company if these assets are disposed of in the ordinary course of business. The assets available for sale consist of 20,000,000 restricted common stock of Big Cat Energy Corporation, approximately 29.6%. It is the Company's policy to report investments at their fair value in the balance sheet.

ASC 820 requires the use of observable market data if such data is available without undue cost and effect.

	Fair Value Measurements at Reporting Date Using			
Description	December 31, 2010	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Securities available for sale	$1,800,000	$1,800,000	$ -	$ -
Warrants issued w/ securities	845,108	-	-	845,108
Total	$2,645,108	$1,800,000	$ -	$ 845,108

Level 3 assets are comprised of the impairment reserve for unevaluated properties. The Company has identified the impairment reserve as a Level 3 due to the lack of available data to obtain market values for the unevaluated properties. The company considered current gas prices and the remaining lease term as a basis for determining the reserve amount.

Level 3 reconciliation table	
Balance, January 1, 2010	$ -
Issued value of warrants	$ 654,300
Increase in value	$ 190,808
Balance, December 31, 2010	$ 845,108

There were no assets measured at fair value as of December 31, 2009.

Financial Instruments

Financial instruments not measured at fair value on a recurring basis include cash and cash equivalents, accounts receivable, accounts payable, accrued liabilities, lines of credit and long-term debt. With the exception of the long-term debt, the financial statement carrying amounts of these items approximate their fair values due to their short-term nature. The carrying amount of long-term debt approximates the fair value due to its floating rate structure.

15. ASSET RETIREMENT OBLIGATION

Changes in the Company's asset retirement obligations were as follows:

	Year Ended December 31, 2010	2009
Asset retirement obligations, beginning of year	$ 33,046	$ 30,907
Liabilities related to acquisitions	8,096,822	--
Revisions in estimated liabilities	39,505	--
Accretion expense	60,257	2,139
Asset retirement obligations, end of year	$ 8,229,630	$ 33,046

16. COMMITMENTS AND CONTINGENCIES

Operating leases

The Company is currently renting office space on a month-to-month basis and has no long-term lease commitments.

Employment contracts:

The Company is party to several employment agreements with key personnel, all of which are effective for a 12-month period beginning January 1, 2011. The agreements range from $80,000 to $175,000 per year and all agreements contain customary terminology as to termination criteria

Delivery Commitments:

A portion of our production is sold under certain contractual arrangements that specify the delivery of a fixed and determinable quantity. The following table sets forth information about material long- term firm transportation contracts for pipeline capacity. These contracts were acquired as part of the acquisition of the Pennaco "North & South Fairway Assets." Under these firm transportation contracts, we are obligated to deliver minimum daily gas volumes, or pay the respective transportation fees for any deficiencies in deliveries. Although exact amounts vary, as of December 31, 2010 we were committed to deliver the following fixed quantities of our natural gas production:

Type of Arrangement	Pipeline System / Location	Deliverable Market	Gross Deliveries (MMBtu/d)	Term
Firm Transport	WIC Medicine Bow	Rocky Mountains	15,000	07/10 –11/15
Firm Transport	Kinder Morgan Trailblazer	Rocky Mountains	22,500	07/10 - 05/12
Firm Transport	Copano Fort Union	Rocky Mountains	10,000	07/10 - 11/11

Environmental impact:

The Company is engaged in oil and gas exploration and production and may become subject to certain liabilities as they relate to environmental cleanup of well sites or other environmental restoration procedures as they relate to the drilling of oil and gas wells and the operation thereof. If the Company acquires existing or previously drilled well bores, the Company may not be aware of what environmental safeguards were taken at the time such wells were drilled or during such time the wells were operated. Should it be determined that a liability exists with respect to any environmental clean up or restoration, the liability to cure such a violation could fall upon the Company. Management believes its properties are operated in conformity with local, state and federal regulations. No claim has been made, nor is the Company aware of any uninsured liability which the Company may have, as it relates to any environmental cleanup, restoration or the violation of any rules or regulations relating thereto.

17. SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. Crude oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment.

The Company retained Mire & Associates, independent third-party reserve engineers, to perform an independent evaluation of proved, possible and probable reserves as of December 31, 2009. Results of drilling, testing and production subsequent to the date of the estimates may justify revision of such estimates. Accordingly, reserve estimates are often different from the quantities of crude oil and natural gas that are ultimately recovered. All of the Company’s reserves are located in the United States.

Reserves

Total reserves are classified by degree of proof as proved, probable, or possible. These classifications are in accordance with the reserves definitions of Rules 4-10(a) (1)-(32) of Regulation S-X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. A description of reserve classifications are as follows:

	Oil (Barrels)	**Gas (MCF)**	Total **MCFE**
Proved Reserves			
Balance – January 1, 2009	-	755,140	755,140
Revisions of previous estimates	-	(72,552)	(72,552)
Extensions, discoveries and			-
other additions	-	-	-
Production	-	(151,028)	(151,028)
Purchase (sales) of minerals	5,020	4,390	34,510
Balance - December 31, 2009	5,020	535,950	566,070
Revisions of previous estimates	(3,627)	(163,582)	(185,356)
Extensions, discoveries and other additions	-	-	-
Production	(1,391)	(741,115)	(729,461)
Purchase (sales) of minerals	-	14,594,149	14,594,148
Balance - December 31, 2010	-	14,245,401	14,245,401

Proved oil and gas reserves—Proved oil and gas reserves are those quantities of oil and gas which by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulation—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

Probable reserves—Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates. As of December 31, 2010, Company does not have any probable reserves.

Possible reserves—Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.   As of December 31, 2010, the Company does not have any possible reserves.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves
The following information is based on the Company's best estimate of the required data for the Standardized Measure of Discounted Future Net Cash Flows as of December 31, 2009 and 2008 in accordance with FASB ASC 932—Disclosures about Oil and Gas Producing Activities which requires the use of a 10% discount rate. This information is not the fair market value, nor does it represent the expected present value of future cash flows of the Company's proved oil and gas reserves.

	2010	2009
Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves		
Future cash inflows	$ 44,984,100	$ 2,198,840
Future production costs	(20,289,800)	1,682,790
Future development costs	(3,225,300)	135,800
Future income tax expenses	-	-
Future net cash flows	21,469,000	380,250
10% annual discount for estimated timing of cash flows	4,606,400	33,140
Standardized measure of discounted future cash flows at the end of the year	$ 16,862,600	$ 347,110

Sources of Changes in Discounted Future Net Cash Flows

Principal changes in the aggregate standardized measure of discounted future net cash flows attributable to the Company's proved crude oil and natural gas reserves, as required by FASB ASC 932-235, at year end are set forth in the table below:

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves	**2010**	**2009**
Standardized measure of discounted future net Cash flows at the beginning of the year	$ 347,110	$ 731,610
Net changes in prices and production costs	45,591	(366,475)
Changes in estimated future development costs	-	-
Sales of oil and gas produced, net of production Costs	(315,792)	(101,451)
Extensions, discoveries and improved recovery less related costs	17,299,708	-
Purchases (sales) of minerals in place	(113,659)	166,560
Revisions of previous quantity estimates	-	(192,114)
Net change in income taxes	-	-
Accretion of discount	34,711	108,980
Change in timing and other	(435,069)	-
Standardized measure of discounted future net Cash flows at the end of the year	$ 16,862,600	$ 347,110

18. SUBSEQUENT EVENTS

Pursuant to FASB ASC 855, management has evaluated all events and transactions that occurred from January 1, 2011 through the date of issuance of the financial statements. During this period we did not have any significant subsequent events, except as disclosed below:

On February 2, 2011, the Company signed a Purchase and Sales Agreement with J.M Huber Corporation in which the Company agreed to purchase approximately 313,000 net acres of leasehold and 2,302 natural gas wells located in Wyoming and Montana for $35,000,000. The Company provided $2,000,000 in non-refundable cash deposits and HPG stock valued at $1,500,000.   The transaction is scheduled to close in April 2011.

On February 3, 2011, the Company executed an agreement with Stephens, Inc. (“Stephens”) pursuant to which Stephens agreed to be the Company’s exclusive financial advisor in connection with a private offering of equity securities of the Company. Stephens may also perform other investment banking services. In consideration for their services, Stephens will receive a $15,000 retainer and be entitled to 6.5% of the gross proceeds of the offering as an offering fee. In addition, Stephens will receive warrants covering that number of securities equal to 105 of the total value of securities actually sold in the offering, exercisable for five years at an exercise price of 110% of the price of the securities sold in the offering. The agreement is for a term of six months, terminable at any time by either party upon 30 days written notice.

On February 24, 2011, the Company executed an agreement with Fletcher International, Ltd. (“Fletcher”) pursuant to which it sold Fletcher warrants to purchase $5,000,000 in shares of the Company’s common stock for a purchase price of $1,000,000.

SIGNATURES

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

HIGH PLAINS GAS, INC.
(the registrant)

By /s/ Brent M. Cook
Brent M. Cook
Chief Executive Officer
(Principal Executive Officer)

By /s/ Joseph M. Hettinger
Joseph M. Hettinger
Chief Financial Officer
(Principal Financial and Accounting Officer)

Date: May 16, 2011

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.

Name	**Title**	**Date**
/s/ Mark D. Hettinger Mark D. Hettinger	Chairman	May 16, 2011
/s/ Joseph Hettinger Joseph Hettinger	Director	May 16, 2011
/s/ Gary Davis Gary Davis	Director	May 16, 2011
/s/ Cordell Fonnesbeck Cordell Fonnesbeck	Director	May 16, , 2011
/s/ Alan R. Smith Alan R. Smith	Director	May 16, 2011

EXHIBIT INDEX

Exhibit No.	Description
3.1	Articles of Incorporation; filed with the Registrant’s Registration Statement on Form SB-2, May 19, 2005
3.2	Bylaws; filed with the Registrant’s Registration Statement on Form SB-2, May 19, 2005
3.3	Amended Articles of Incorporation – changing name from Northern Explorations, Ltd. to High Plains Gas, Inc.; filed October 6, 2010 on Form 8-K
3.4	Unofficial restated certificate of incorporation of the registrant as amended to date filed (on April 1, 1998) as Exhibit 4.1 to registrant’s Registration Statement on Form S-8, File Number 333-49095 and hereby incorporated by reference.
3.5	By-laws of the registrant as amended effective October 14, 2005, filed (on December 12, 2005) as Exhibit 3.2 to registrant's Quarterly Report on Form 10-Q for the quarterly period ended October 31, 2005, and hereby incorporated by reference.
3.6	Certificate of Amendment to Articles of Incorporation increasing authorized common stock to 250,000,000 shares and including a class of 20,000,000 shares of Preferred Stock; filed on Form 8-K March 15, 2011
4.1	High Plains Gas, Inc. 2011 Employee and Consultant Stock Option Plan; filed with Registration Statement on Form S-8 March 11, 2011
10.1	Reorganization Agreement – between Northern Explorations, Ltd., (“NXPN”) a Nevada Corporation, and High Plains Gas, LLC, a Wyoming limited liability company (“HPG”), dated July 28, 2010; filed with the Registrant’s Current Report on Form 8-K, August 8, 2010 as Exhibit 10.1
10.2	Amendment to the Reorganization Agreement - dated July 28, 2010, made and entered into as of September 13, 2010, by and between High Plains Gas, LLC, a Wyoming limited liability company (“HPG”), and Northern Explorations, LTD., In (“NXPN”) a Nevada Corporation; filed on Form 8-K, October 6, 2010
10.3	Agreement – Installment or Single Payment Note, Between High Plains Gas, LLC and U.S. Bank, dated January 20,2010 as amended; filed on Form 8-K October 22, 2010
10.4	Agreement – Mortgage Security Agreement, Financing statement and Assignment of Production, Between High Plains Gas, LLC and Jim’s Water Service, Inc.: April 6, 2010. ; filed on Form 8-K October 22, 2010
10.5	Agreement – Master Agreement Regarding Redemption of Membership Units By High Plains Gas, LLC, Formation of M&H Resources, LLC, And Distribution And Assignment Of Certain Interests in Specific Oil and Gas Leases (the "Agreement"), effective May 5, 2010; between High Plains Gas, LLC ("HPG"), its Members. ; filed on Form 8-K October 22, 2010
10.6	Agreement – Settlement and Well Buyout Agreement, Financing statement and Assignment of Production, between High Plains Gas, LLC and Alpha Wyoming Land Company, LLC; dated December 9, 2010; filed on Form 8-K October 22, 2010
10.7	Amended and Restated Operations and Convertible Note Purchase Agreement dated as of September 30, 2010 by and among High Plains Gas, LLC, Current Energy Partners Corporation and CEP-M Purchase, LLC; filed on Form 8-K November 22, 2010
10.8	Option Agreement dated October 31, 2010 by and between High Plains Gas, LLC, and Current Energy Partners Corporation; filed on Form 8-K November 22, 2010
10.9	Purchase and Sale Agreement among Current Energy Partners Corporation, CEP M Purchase LLC and Pennaco Energy, Inc. dated July 25, 2010; filed on Form 8-K December 1, 2010
10.10	Amendment dated November 24, 2010 to Option Agreement dated October 31, 2010 by and between High Plains Gas, LLC, and Current Energy Partners Corporation; filed on Form 8-K December 1, 2010
10.11	Purchase and Sale Agreement dated December 10, 2010 by and among High Plains Gas, LLC and Duramax Holdings, LLC; filed on Form 8-K December 14, 2010
10.12	Stock Purchase Agreement dated December 8, 2010 by and among High Plains Gas, LLC and Big Cat Energy Corporation; filed on Form 8-K December 15, 2010

10.13	Agreement between Fletcher International, Ltd. and High Plains Gas, Inc. dated as of February 24, 2011; filed on Form 8-K March 1, 2011
10.14	Warrant Certificate for Warrants to Purchase Shares of Common Stock of High Plains Gas, Inc. issued to Fletcher International, Ltd. on February 24, 2011; filed on Form 8-K March 1, 2011
10.15	Purchase and Sale Agreement between J.M. Huber Corporation and High Plains Gas, Inc. dated February 2, 2011; filed on Form 8-K March 15, 2011
10.16	Credit Agreement between CEP-M Purchase, LLC, Amegy Bank National Association as Administrative Agent and Letter of Credit Issuer, and signatory lenders, dated November 19, 2010; filed on Form 8-K March 24, 2011
10.17	Promissory Note issued by CEP-M Purchase, LLC to Amegy Bank National Association dated November 19, 2010; filed on Form 8-K March 24, 2011
10.18	Security Agreement by CEP-M Purchase, LLC in favor of Amegy Bank National Association as Collateral Agent dated November 19, 2010; filed on Form 8-K March 24, 2011
10.19	Mortgage, Security Agreement, Financing Statement and Assignment of Production from CEP-M Purchase, LLC to Amegy Bank National Association as Collateral Agent effective November 19, 2010; filed on Form 8-K March 24, 2011
10.20	Employment Agreement between the Company and Mark D. Hettinger dated as of January 1, 2011; filed with original filing of this Form 10-K on April 18, 2011
10.21	Employment Agreement between the Company and Brent M. Cook dated as of January 1, 2011; filed with original filing of this Form 10-K on April 18, 2011.
10.22	Employment Agreement between the Company and Joseph Hettinger dated as of January 1, 2011; filed with original filing of this Form 10-K on April 18, 2011.
10.23	Employment Agreement between the Company and Brandon Hargett dated as of January 1, 2011; filed with original filing of this Form 10-K on April 18, 2011.
10.24^	Netherland, Sewell & Associates, Inc. reserve report as of December 31, 2010, dated February 14, 2011.
21	Subsidiaries of registrant; filed with original filing of this Form 10-K on April 18, 2011.
31.1^	Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (Rule 13a-14(a) or Rule 15d-14(a)).
31.2^	Certification of the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (Rule 13a-14(a) or Rule 15d-14(a)).
32.1^	Certification by the Chief Executive Officer of High Plains Gas, Inc. pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. 1350).
32.2^	Certification by the Chief Financial Officer of High Plains Gas, Inc. pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. 1350).

^ Filed herewith

EXHIBIT 10.24

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

CHAIRMAN & CEO
C.H. (SCOTT) REES III
PRESIDENT & COO
DANNY D. SIMMONS
EXECUTIVE VP
G. LANCE BINDER

EXECUTIVE COMMITTEE
P. SCOTT FROST - DALLAS
J. CARTER HENSON, JR. - HOUSTON
DAN PAUL SMITH - DALLAS
JOSEPH J. SPELLMAN - DALLAS
THOMAS J. TELLA II - DALLAS

February 14, 2011

Mr. Brandon W. Hargett
High Plain Gas, Inc.
3601 Southern Drive
Gillette, Wyoming 82717

Dear Mr. Hargett:

In accordance with your request, we have estimated the proved, probable, and possible reserves and future revenue, as of December 31, 2010, to the High Plain Gas, Inc. (HPG) interest in certain coalbed methane properties located in the Powder River Basin, Wyoming. HPG acquired its interest in the majority of these properties in 2010. We completed our evaluation on February 14, 2011. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by HPG. The estimates in this report have been prepared in accordance with the definitions and guidelines of the U.S. Securities and Exchange Commission (SEC) and conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, except that per-well overhead expenses are excluded for operated properties and future income taxes are excluded for all properties. Definitions are presented immediately following this letter. This report has been prepared for HPG's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the gas reserves and future net revenue to the HPG interest in these properties, as of December 31, 2010, to be:

	Gas Reserves		Future Net Revenue ($)	
Category	Gross (MCF)	Net (MCF)	Total	Present Worth at 10%
Proved Developed Producing	9,389,434	6,357,905	9,136,600	8,301,500
Proved Developed Non-Producing	7,474,463	5,253,624	9,137,900	7,167,900
Proved Undeveloped	4,093,289	2,613,872	3,194,500	1,393,200
Total Proved	20,957,186	14,225,401	21,469,000	16,862,600
Probable Developed	31,041,451	15,973,270	29,558,600	22,564,200
Probable Undeveloped	87,752,757	55,580,483	78,061,800	33,702,000
Total Probable	118,794,208	71,553,753	107,620,400	56,266,200
Possible Developed	27,490,451	6,862,488	14,471,700	10,383,500
Possible Undeveloped	95,848,508	62,726,123	80,437,500	33,829,600
Total Possible	123,338,959	69,588,611	94,909,200	44,213,100

Gas volumes are expressed in thousands of cubic feet (MCF) at standard temperature and pressure bases.

The estimates shown in this report are for proved, probable, and possible reserves. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Future gross revenue to the HPG interest is prior to deducting state production taxes and ad valorem taxes. Future net revenue is after deductions for these taxes, future capital costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability. Also, our estimates do not include any salvage value for the lease and well equipment or the cost of abandoning the properties.

Gas prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2010. The average CIG Rocky Mountains spot price of $3.945 per MMBTU is adjusted by area for energy content and transportation fees. All prices are held constant throughout the lives of the properties. For the proved reserves, the average adjusted gas price weighted by production over the remaining lives of the properties is $3.162 per MCF.

Lease and well operating costs used in this report are based on operating expense records of HPG and the previous owners of the properties. For nonoperated properties, these costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. As requested, lease and well operating costs for the operated properties include only direct lease- and field-level costs. For all properties, headquarters general and administrative overhead expenses of HPG are not included. Lease and well operating costs are held constant throughout the lives of the properties. Capital costs are included as required for workovers, new development wells, and production equipment. The future capital costs are held constant to the date of expenditure.

We have made no investigation of potential gas volume and value imbalances resulting from overdelivery or underdelivery to the HPG interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on HPG receiving its net revenue interest share of estimated future gross gas production.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of HPG to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and guidelines. A substantial portion of these reserves are for behind-pipe zones, non-producing zones, undeveloped locations, and producing wells that lack sufficient production history upon which performance-related estimates of reserves can be based. Therefore, these reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from HPG, previous owners of the properties, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting geoscience, performance, and work data are on file in our office. The titles to the properties have not been examined by NSAI, nor has the actual degree or type of interest owned been independently confirmed. The technical persons responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-002699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ Dan Paul Smith
Dan Paul Smith, P.E. 49093
Senior Vice President

Date Signed: February 14, 2011

By: /s/ John G. Hattner
John G. Hattner, P.G. 559
Senior Vice President

Date Signed: February 14, 2011

DWB:ART

Exhibit 31.1

CERTIFICATIONS

I, Brent M. Cook, certify that:

1. I have reviewed this Amendment No. 2 to the Annual Report on Form 10-K of High Plains Gas, Inc. for the period ending December 31, 2010;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting procedures;

   (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the Company's most recent fiscal quarter (the Company's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):

   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Company's internal control over financial reporting.

Date: May 17, 2011

/s/ Brent M. Cook
Brent M. Cook
Chief Executive Officer (Principal Executive Officer)

Exhibit 31.2

CERTIFICATIONS

I, Joseph Hettinger, certify that:

1. I have reviewed this Amendment No. 2 to the Annual Report on Form 10-K of High Plains Gas, Inc. for the period ending December 31, 2010;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting procedures;

    (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the Company's most recent fiscal quarter (the Company's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):

    (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Company's internal control over financial reporting.

Date: May 17, 2011

/s/ Joseph Hettinger
Joseph Hettinger
Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
(18 U.S.C. 1350)

In connection with Amendment No. 2 to the Annual Report of High Plains Gas, Inc. (the "Company") on Form 10-K for the year ended December 31, 2010, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Brent M. Cook, Chief Executive Officer of the Company, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. 1350), that to my knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Brent M. Cook
Brent M. Cook
Chief Executive Officer
(Principal Executive Officer)
May 17, 2011

Exhibit 32.2

CERTIFICATION PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
(18 U.S.C. 1350)

In connection with Amendment No. 2 to the Annual Report of High Plains Gas, Inc. (the "Company") on Form 10-K for the year ended December 31, 2010, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Joseph Hettinger, Chief Financial Officer of the Company, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. 1350), that to my knowledge:

1. the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Joseph Hettinger
Joseph Hettinger
Chief Financial Officer
May 17, 2011