

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

FORM 10-K

(Mark One)

: ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 For the fiscal year ended
October 31, 2009

9 TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____ to _____

Commission file number: **333-102441**

BRINX RESOURCES LTD.
(Exact name of registrant as specified in its charter)

Nevada
(State or other jurisdiction of incorporation or organization)

98-0388682
(I.R.S. Employer Identification No.)

820 Piedra Vista Road NE, Albuquerque, NM 87123
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: **(505) 250-9992**

Securities registered under Section 12(b) of the Act: **None**
Securities registered under Section 12(g) of the Act: **None**

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
 Yes No (Not required)

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

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

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

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter. **\$2,616,940 as of April 30, 2009**

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: **24,529,832 as of January 20, 2010**

DISCLOSURE REGARDING FORWARD-LOOKING STATEMENTS

This report includes "forward-looking statements." All statements other than statements of historical facts included or incorporated by reference in this report, including, without limitation, statements regarding our future financial position, business strategy, budgets, projected costs and plans and objectives of management for future operations, are forward-looking statements. In addition, forward-looking statements generally can be identified by the use of forward-looking terminology such as "may," "will," "expect," "intend," "project," "estimate," "anticipate," "believe," or "continue" or the negative thereof or variations thereon or similar terminology. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we cannot give any assurance that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from our expectations ("Cautionary Statements") include, but are not limited to, our assumptions about energy markets, production levels, reserve levels, operating results, competitive conditions, technology, the availability of capital resources, capital expenditure obligations, the supply and demand for oil and gas, the weather, inflation, the availability of goods and services, oil and natural gas drilling risks, general economic conditions (either internationally or nationally or in the jurisdictions in which we are doing business), legislative or regulatory changes (including changes in environmental regulation, environmental risks and liability under federal, state and foreign environmental laws and regulations), the securities or capital markets and other factors disclosed under "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," "Item 2. Properties" and elsewhere in this report. All subsequent written and oral forward-looking statements attributable to us, or persons acting on our behalf, are expressly qualified in their entirety by the cautionary statements. We assume no duty to update or revise our forward-looking statements based on changes in internal estimates or expectations or otherwise.

"Bbl" is defined herein to mean one stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

"Mcf" is defined herein to mean one thousand cubic feet of natural gas at standard atmospheric conditions.

"Working interest" is defined herein to mean an interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations. The share of production to which a working interest owner is entitled will always be smaller than the share of costs that the working interest owner is required to bear, with the balance of the production accruing to the mineral owners of royalties.

PART I

ITEM 1. BUSINESS.

We are an independent oil and gas company engaged in exploration, development and production of oil and natural gas. As production of these products continues, they will be sold to purchasers in the immediate area where the products are produced.

Until 2005, our focus was on our undeveloped mineral interests and we were considered, at that time, to be a development stage company engaged in the acquisition and exploration of mineral and oil and gas properties. We still hold an interest in undeveloped mineral interests located in New Mexico (the "Antelope Pass Project"). However, in 2005, we suspended activities on our undeveloped mineral properties indefinitely in order to focus on our oil and gas properties and we did not conduct any operations or exploration activities on our undeveloped mineral properties during the fiscal year ended October 31, 2009.

During 2005 and 2006, we acquired undeveloped oil and gas interests and commenced exploration activities on those interests. Our undeveloped oil and gas interests are located in Oklahoma, Mississippi and California. In 2006, we commenced oil and gas production and started earning revenues. Prior to 2006, we were considered a development stage company as defined by Statement of Financial Accounting Standards No. 7 ("SFAS 7"). Effective 2006, we ceased being considered a development stage company.

Our plan of operations is to continue to produce commercial quantities of oil and gas and to drill re-entries to test the oil and gas productive capabilities of our oil and gas properties. As noted above, we have suspended our efforts indefinitely on the Antelope Pass Project in order to focus on our oil and gas interests.

Corporate Background

We were incorporated under the laws of the State of Nevada on December 23, 1998, initially to explore mining claims and property in New Mexico.

Property Acquisitions and Dispositions

Owl Creek Project

On August 10, 2005, we acquired a 70% working interest in Ranken Energy Corporation's Owl Creek Project for a total buy-in cost of \$211,750 plus dry hole costs (the "Owl Creek Project"). The Owl Creek Project is located in Oklahoma. Our working interest in the Owl Creek Project included leasehold interests, two re-entry test wells, geologic expenses, brokerage costs, 3-D seismic usage, geophysical interpretations, and overhead.

On June 1, 2006, we completed the sale of 20% of the Powell #2 well and future drill sites on the Owl Creek Project. We received a one-time cash payment of \$300,000, with each party responsible for its portion of the cost to complete the Powell #2 well and future drill sites.

Also in June 2006, we acquired a 50% interest in an additional 85 leased acres located at the eastern end of the Owl Creek Project, increasing the project's scope to over 1,200 acres. We paid \$17,000 for the additional acreage.

On August 3, 2006, we completed the sale of 7.5% of the Isbill #1 well and future drill sites on the Owl Creek Project. We received a one-time cash payment of \$100,000. We retained a 42.5% working interest in the Owl Creek Project, with each party responsible for its portion of the costs to drill and complete the Isbill #1 well and future drill sites. We also retained a 70% interest in two spacing unit and the wells containing the Johnson #1 and Powell #1 wells and a 50% interest in one spacing unit and the well containing the Powell #2 well.

On March 15, 2007, we expended \$403,675 on Isbill #2-36 well in which we held a 42.5% working interest. On October 19, 2007, we expended \$238,784 on Powell #3-25 well, in which we held a 42.5% working interest.

On August 29, 2008, we sold our working interests in the Owl Creek Project to an unrelated third party for net proceeds of \$3,068,544.

Three Sands Project

On October 6, 2005, we acquired a 40% working interest in Vector Exploration Inc.'s Three Sands Project for a total buy-in cost of \$88,000 plus dry hole costs (the "Three Sands Project"). The Three Sands Project is located in Oklahoma. For the year ended October 31, 2006, we expended \$530,081 in exploration costs. In June 2007, we acquired a 40% working interest in the William #4-10 well for a total cost of \$285,196 and paid a further \$17,000 in costs relating to the well. On March 19, 2008, we participated in the KC 80 #1-11 well and paid \$75,000 for the prepaid drilling costs. During March and April 2008, we expended an additional amount of \$48,763 for the intangible and tangible costs, and \$161,650 during May to July 2008. The total cost of the Three Sands Project as of October 31, 2009 was \$1,197,523. Our working interest in the Three Sands Project includes leasehold interests, one re-entry production well, and two drilling wells. We also participate in drilling operations and related costs, in proportion to our working interest.

Palmetto Point Project

On February 28, 2006, we acquired a 10% working interest before completion and an 8.5% revenue interest after completion, in a 10-well program at the Palmetto Point Project operated by Griffin & Griffin Exploration LLC ("Griffin & Griffin") for a total buy-in cost of \$350,000 (the "Palmetto Point Project"). The Palmetto Point Project is located in Mississippi. On September 26, 2006, we acquired two additional wells (the PP F-6B and PP F52-A wells) within the Palmetto Point Project for \$70,000. On October 1, 2007, we acquired and participated in drilling two more wells within the Palmetto Point Project (the PP F-12-2 and PP F-12-3 wells) at a cost of \$69,862. On October 25, 2007, we paid \$17,000 for a sidetrack, a deviation of the existing PP-F-12-3 well at an angle to reach additional targeted oil sands. The well was successfully completed as a flowing oil well.

On January 30, 2008, we incurred \$36,498 for workovers to install submersible pumps. During November 2008 to July 2009, we incurred \$44,623 for the Belmont Lake Project. The total cost of the Palmetto Point Project, including costs for the PP F-12-2, PP F-12-3, PP F-12-4 and PP F-52 wells, was \$641,820 as of October 31, 2009.

Mississippi Frio-Wilcox Joint Venture

On August 2, 2006, we executed a memorandum agreement with Griffin & Griffin (as operator of the project), Delta Oil and Gas, Inc., Turner Valley Oil and Gas Company, Lexaria Corp., a Nevada corporation ("Lexaria"), and the Stallion Group to participate in two proposed drilling programs located in Southwest Mississippi and Northeast Louisiana, comprised of up to 50 natural gas and/or oil wells, at a price of \$400,000 (the "Mississippi Frio-Wilcox Joint Venture"). We hold a 10% working interest in the Mississippi Frio-Wilcox Joint Venture project before production and a prorated reduced working interest after production based on the operator's interest portion.

On June 21, 2007, we assigned our future development interests and obligations for any new wells on our Mississippi Frio-Wilcox Joint Venture property to Lexaria for the sum of \$1. We believe the assigned interests to be of nominal value. We have maintained our original interest, rights, title and benefits to all seven wells drilled with our participation at the Mississippi Frio-Wilcox Joint Venture property between August 3, 2006 and June 19, 2007, specifically wells CMR-USA-39-14, Dixon #1, Faust #1 TEC F-1, CMR/BR F-14, RB F-1 Red Bug #2, BR F-33, and Randall #1 F-4, and any offset wells that could be drilled to any of these specified wells. We do not anticipate expending additional exploration funds on the project.

2008-3 Drilling Program, Oklahoma

On January 12, 2009, we acquired a 5% working interest in Ranken Energy Corporation's 2008-3 Drilling Program for a total buy-in cost of \$28,581. We agreed to participate in the drilling operations to casing point in the initial test well of each prospect. The Before Casing Point ("BCP") Interest shall be 6.25% and the After Casing Point ("ACP") Interest shall be 5.00%. From January to July 2009, we expended an additional \$213,925. The well,

Wigley #1-11, was abandoned during March 2009, and the cost of \$23,510 was moved to the proved properties pool. Selman #1-21 and Bagwell #1-20 started producing during May 2009, Ard #1-36 started producing during June 2009, and Selman #2-21 started producing during July 2009. The interests are located in Garvin County, Oklahoma. The total cost of the 2008-3 Drilling Program was \$258,980 as of October 31, 2009.

2009-2 Drilling Program, Oklahoma

On June 19, 2009, we acquired a 5% working interest in Ranken Energy Corporation's 2009-2 Drilling Program for a total buy-in cost of \$26,563. We agreed to participate in the drilling operations to casing point in the initial test well of each prospect. The BCP Interest shall be 6.25% and the ACP Point Interest shall be 5.00%. The well, James #1-18, was abandoned on September 21, 2009. The cost of \$33,663 was moved to the proved properties pool. The interests are located in Garvin County, Oklahoma.

2009-3 Drilling Program, Oklahoma

On August 12, 2009, we acquired a 5.00% working interest in Ranken Energy Corporation's 2009-3 Drilling Program for a total buy-in cost of \$37,775. We agreed to participate in the drilling operations to casing point in the initial test well of each prospect. The BCP Interest shall be 6.25% and the ACP Interest shall be 5.00%. The total costs, including drilling costs, for the year ended October 31, 2009 were \$137,356.

King City, California

Late in the quarter ending July 31, 2009, we entered into an agreement with Sunset Exploration to explore for oil and gas on 10,000 acres located in west central California. The agreement calls for us to earn a 20% working interest in the project by funding a maximum of 50% of a \$200,000 geophysical survey composed of gravity and seismic surveys and agreeing to carry Sunset Exploration for 40% of dry hole cost of the first well. Completions and drilling of this first well and completion of subsequent wells on the 10,000 acres will be proportionate to each parties' working interest.

International Exploration Program

The Company is attempting to expand its property base by locating other resource properties internationally. Accordingly, we have hired consultants to gather data on properties that may be of interest to us. The consultants on a best efforts basis will attempt to acquire option agreements, lease agreements and/or the outright purchase of oil and /or gas properties internationally. As of the date of this filing, we have not found a suitable acquisition.

Antelope Pass Project

In September 2002, we acquired a 100% interest in leases on unpatented lode mining claims in the Antelope Pass Project, located in the Hidalgo County, New Mexico for \$811, from Leroy Halterman, who was a non-affiliate of our company at that time. The Antelope Pass Project consists of the Kendra 1 through Kendra 8 mineral claims. Unpatented claims are mining claims for which the holder has no patent, or document that conveys title. The 2009-2010 Bureau of Land Management maintenance fee has been paid and the claims are valid until September 2010 without any additional expenditure. We have suspended our efforts indefinitely on the Antelope Pass Project.

Exploration and Acquisition Capital Expenditures

During the fiscal years ended October 31, 2009, 2008, and 2007, we incurred \$668,446, \$291,150, and \$1,400,943, respectively, in identifying and acquiring oil and natural gas interests, and for exploration costs.

Principal Products

We conduct exploration activities to locate oil and natural gas. As we continue our production of these products, we anticipate that generally they will be sold to purchasers in the immediate area where the products are

produced. We expect that the principal markets for oil and natural gas will continue to be refineries and transmission companies that have facilities near our producing properties.

Competition

Oil and gas exploration, mineral exploration and acquisition of undeveloped properties are highly competitive and speculative businesses. We compete with a number of other companies, including major mining and oil and gas companies and other independent operators that are more experienced and which have greater financial resources. We do not hold a significant competitive position in either the mining industry or the oil and gas industry.

Major Customers

During the fiscal years ended October 31, 2009 and 2008, we collected \$171,418 (43%) and \$953,846 (64%), respectively, of our revenues from Ranken Energy Corporation, the operator of the Owl Creek Project. Because we sold all of our working interests in the Owl Creek Project in August 2008, we were less dependent on Ranken Energy Corporation for a substantial portion of our revenues in fiscal year 2009. However, we work with only a few operators. Therefore, we will continue to be dependent on these few operators for a substantial portion of our revenues in fiscal year 2010.

Compliance with Government Regulation

Our oil and gas operations are subject to various levels of government controls and regulations in the United States. Legislation affecting the oil and gas industry has been pervasive and is under constant review for amendment or expansion. Pursuant to such legislation, numerous federal, state and local departments and agencies have issued extensive rules and regulations binding on the oil and gas industry and its individual members, some of which carry substantial penalties for failure to comply. Such laws and regulations have a significant impact on oil and gas drilling, gas processing plants and production activities, increase the cost of doing business and, consequently, affect profitability. Inasmuch as new legislation affecting the oil and gas industry is commonplace and existing laws and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws and regulations. A breach or violation of such laws and regulations may result in the imposition of fines and penalties. At present, we do not believe that compliance with environmental legislation and regulations will have a material effect on our operations; however, any changes in environmental legislation or regulations or in our activities may cause compliance with such legislation and/or regulation to have a material impact on our operations. In addition, certain types of operations require the submission and approval of environmental impact assessments. Environmental legislation is evolving in a manner that means stricter standards, and enforcement, fines and penalties for non-compliance are becoming more stringent. Environmental assessments of proposed projects carry a heightened degree of responsibility for companies and directors, officers and employees. The cost of compliance with changes in governmental regulations has a potential to reduce the profitability of operations. We intend to ensure that we comply fully with all environmental regulations relating to our operations.

With respect to our Oklahoma oil and gas interests, we are required to file Oklahoma Form 1000 and pay \$100 to obtain state permits for oil and gas drill sites on private lands. With respect to our Mississippi oil and gas interests, we are required file Mississippi Form 2 and pay \$350 to obtain state permits for oil and gas drill sites on private lands. Although we do not presently hold any interest in leases on state or federal lands, in the future we may be required to obtain environmental assessments in connection with wildlife impacts or archeological clearances.

With respect to our Antelope Pass Project, we will be required to conduct all mineral exploration activities in accordance with the Bureau of Land Management ("BLM") of the United States Department of the Interior. If we proceed with our Antelope Pass Project, we will be required to obtain a permit prior to the initiation of exploration. To obtain a permit we will have to submit plans of operations to both the BLM and the State of New Mexico as part of our permit application.

Employees

Leroy Halterman serves as our president and secretary and a director. As of the date of this report, Mr. Halterman receives monthly management fees of \$5,000 and a reimbursement for office space. For the fiscal years ended October 31, 2009 and 2008, we incurred \$60,000 and \$57,000, respectively, for Mr. Halterman's services.

We have engaged Kulwant Sandher to serve as our chief financial officer on a part-time basis and pay him CAD\$2,500 per month.

We pay management fees of \$7,500 per month to Kenneth Cabianca, one of our directors.

For the fiscal years ended October 31, 2009 and 2008, we incurred \$60,500 and \$48,128, respectively, for administrative services performed by Downtown Consulting. Downtown Consulting is an entity owned and controlled by Sarah Cabianca, the daughter of Kenneth Cabianca and one of our shareholders. We pay Downtown Consulting a monthly fee of \$5,000 for its services. We anticipate that we will be conducting most of our business through agreements with consultants and third parties. We have not entered into any arrangements or negotiations with any other consultants or third parties and our employees are not covered under a collective bargaining agreement.

ITEM 1A. RISK FACTORS.

Not required for smaller reporting companies.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

Not required for smaller reporting companies.

ITEM 2. PROPERTIES.

Oil and Gas Properties

Current Oklahoma Projects

2008-3 Drilling Program, Oklahoma. On January 12, 2009, we acquired a 5% working interest in Ranken Energy Corporation's 2008-3 Drilling Program for a total buy-in cost of \$28,581. We agreed to participate in the drilling operations to casing point in the initial test well of each prospect. The BCP Interest shall be 6.25% and the ACP Interest shall be 5.00%. From January 2009 to July 2009, we expended an additional \$213,925. The total cost of the 2008-3 Drilling Program as of October 31, 2009 was \$258,980. The interests are located in Garvin County, South Central Oklahoma.

This program is composed of four 3-D seismically defined separate prospects with one exploratory well in three of the prospects and two in the fourth prospect. Targeted pay zones include the prolific Bromide Sands, Viola Limestone, Deese Sandstone and Layton Sandstone. One of the wells has very similar geology and structure to the Bromide sands in the Owl Creek field.

Five wells were drilled during 2009. Production casing was set on four of the five wells and the fifth well was deemed non-commercial and was plugged and abandoned. All four completed wells are producing commercial quantities of oil and gas with one well producing most of the oil. As of October 31, 2009 the wells in this program have produced a total of 68,392 Bbls of oil and 28,775 Mcf of natural gas.

2009-2 Drilling Program, Oklahoma. On June 15, 2009, we acquired a 5% working interest in Ranken Energy Corporation's 2009-2 Drilling Program for a total buy-in cost of \$26,563. We agreed to participate in the drilling operations to casing point in the initial test well of each of three prospects. The BCP Interest shall be 6.25% and the ACP Interest shall be 5.00%. The interests are located in Garvin County, Oklahoma. A total of three wells were drilled in this program and targeted pay zones that were the same as in the 2008-3 program. The zones included the prolific Oil Creek, Bromide Sands, Viola, Deese and Layton Sandstone. This program is composed of

three 3-D seismically defined separate prospects. All wells were drilled in the last fiscal quarter of 2009. Two of the wells were deemed non-commercial and were plugged and abandoned. Production casing was set on one of the three wells and completion efforts have started.

2009-3 Program, Oklahoma. On August 12, 2009, we acquired a 5% working interest in Ranken Energy Corporation's 2009-3 Drilling Program for a total buy-in cost of \$37,775. We agreed to participate in the drilling operations to casing point in the initial test well on each of four prospects. The BCP Interest shall be 6.25% and the ACP Interest shall be 5.00%. The interests are located in Garvin County, Oklahoma. Targeted pay zones include the prolific Oil Creek, Bromide Sands, Viola and Deese sands. This program is composed of four 3-D seismically defined separate prospects with one exploratory well in each of the four prospects. Three of the four wells have been drilled and production casing has been set on all three. Two of the wells had successful drill stem test that flowed oil and gas to the surface. Electric and radiation logs indicate multiple pay zones in all three wells. The fourth well has yet to be drilled but should be drilled in the first quarter of 2010.

Three Sands Project

Location and Access. The Three Sands Project is an oil and gas exploration project located in Noble County, Oklahoma. The property can be reached by Oklahoma State Highway 77 and then accessed by a secondary gravel and dirt road.

Previous Operations and History. The Three Sands field was drilled on 10-acre spacing in the 1920s and 1930s and was very active in producing over 200 million Bbls of oil and an unknown amount of gas from a six-section (3,800 acres) area. However, during this period, most wells were abandoned within twenty years as the wells became commercially unviable due to the lack of technology. In particular, during this period, technology was not available, as it is today, to handle high volumes of water and its subsequent disposal, nor was it capable of drilling in areas where the tightness of rock limited flow.

The primary targets of the Three Sands Project are the Arbuckle, Wilcox and Viola Formations. These were the deep pay zones first discovered in the field, and in addition to the oil they produced, large amounts of water were eventually produced forcing the abandonment of the well. Today the water problem has been overcome with down hole electrical high volume pumps and adequate disposal wells, allowing continued exploration.

Geology of the Three Sands Project. Geologically, this field is a banded structure in which a combination of structure and erosion has aided in producing the field. Pay zones in the project vary from the Arbuckle to the Pennsylvanian and are productive over a 5,000-foot interval that starts at less than 1,000 feet from the surface. In a 2004 drill test, more than two-dozen pay zones were encountered (some of which have not been produced).

Costs Including Previous Work. As of October 31, 2009, we have expended \$1,197,523 in connection with the Three Sands Project, including leasing, title, drilling, and casing.

Present Activities. Drilling of the Kodesh #1 disposal well was completed on October 3, 2005 and drilling of the Kodesh #2 well was completed on October 23, 2005. Completion and equipping of these wells took place during mid-December 2005 through early January 2006. The Kodesh #1 is being used for salt water disposal well. The Kodesh #2 well no longer produces oil on a daily basis, but there is a small amount of natural gas being produced. As of August 2009, it has produced 3,690 Bbls of oil and 6,342 Mcf of natural gas. At the time of this report, the Kodesh #2 well is not producing oil because of a failure of the downhole pump which needs either to be repaired or replaced.

During January 2007, we re-entered the Dye Estate #1 well. Production of natural gas from the Dye Estate #1 well commenced in mid-August 2007. As of October 31, 2009, the Dye Estate #1 well has produced 4,862 Mcf of natural gas and is currently averaging natural gas production at a rate of 5 Mcf per day. Water from the Dye Estate #1 well is being disposed in the Kodesh #1 disposal well.

We commenced drilling the William #4-10 well in early June 2007, reaching a total depth of 4,810 feet in mid-June 2007. Electric and radiation logs indicated that the William #4-10 well contained four potential commercial pay zones, the Wilcox Sand, Mississippi Lime, Layton Sand and the Tonkawa Sand. Completion of the

lowest zone, the Wilcox Sand, occurred in mid-August 2007. Production from the William #4-10 well started in mid-October 2007. During the first quarter of 2008, we perforated, fracture treated and tested the Mississippi Lime and the lower Layton Sand to increase the production rate of both gas and oil from the William #4-10 well and provide data regarding the potential of these formations for the remainder of the leases on the Three Sands Project. As of October 31, 2009, the William #4-10 well has produced 2,136 Bbls oil and 34,009 Mcf of gas.

Drilling commenced on the KC 80 #1-11 well in mid-February 2008 and reached total depth of 4,720 feet by the end of February 2008. The KC 80 #1-11 has been surveyed with radiation and electrical logs. The primary target for the well is the upper Mississippian Limestone and Chat Formation. The KC-80 well's logs indicate significant thickness of Chat and upper Mississippi Limestone with good porosity, permeability, and hydrocarbon shows.

Completion of the KC 80 #1-11 well started in late April 2008. The lowest pay zone, the Mississippian, was acidized and partially fracture treated. In early August a similar treatment was given to the Chat zone or the horizon that lies above the lowest pay zone. As of October 31, 2009, the KC 80 #1-11 well is producing at a rate of 4 Bbls of oil and 35 Mcf of natural gas daily. As of October 31, 2009, the KC 80 #1-11 has produced 4,426 Bbls of oil and 21,115 Mcf of natural gas.

Palmetto Point Project

Location and Access. The Palmetto Point Project is located on the border of southern Mississippi and Louisiana along the floodplain of the Mississippi river. The area is approximately 20 miles west of Woodville, Mississippi and approximately 50 miles northwest of Baton Rouge, Louisiana. The wells are located in Township 2 North, Ranges 4 & 5, in West Adams and Wilkinson Counties in the state of Mississippi. The area may be accessed via Interstate 55 (approximately 100 miles south of Jackson, Mississippi) and then west via state highways. The drill locations are accessed by secondary gravel and dirt roads. Transporting natural gas to the market will be accomplished via a series of pipelines which cross the project area.

Previous Operations and History. Griffin & Griffin, the operator for the Palmetto Point Project, has over 40 years of operations history in the Palmetto Point Project area and has acquired substantial data and 3-D seismic data for the Palmetto Point Project. To date, Griffin & Griffin has drilled, owned or operated more than 100 Frio wells in the region. More specifically, Griffin & Griffin has drilled to a subsurface depth and has penetrated the sands of the Frio Formation on the Palmetto Point Project.

Geology of the Palmetto Point Project. The prospect wells were located to test the Frio Geological Formation. Frio wells typically enjoy low finding costs. Griffin & Griffin has utilized seismic "bright spot" technology, which helps to identify gas reservoirs and to delineate reservoir geometry and limits. The term "bright spot" is used to describe a geophysical amplitude anomaly, which is simply a velocity change from a higher velocity to lower velocity. Sands that contain gas are predictable by this method because the gas will provide a slower velocity response giving an abnormally intense trough-peak reflections, therefore termed a "bright spot". The data evaluation in the Frio section gives a direct hydrocarbon indication ("HCI") allowing one to not only see gas seismically, but also the lateral extent of each gas reservoir at various depths to include multiple horizons at some locations.

The gas targets at the Palmetto Point Project occur at shallow depths and have minimal completion costs. The Frio project in the area of Southwest Mississippi and North-Central Louisiana is a very complex series of sand representing marine transgressions and regressions and resulting in the presence of varying depositional environments. Structurally, the Frio gas accumulations are a function of local structure and/or structural nose formed as a result of differential compaction features. However, stratigraphic termination (updip pinchout of sands within shales) also plays a role in most Frio accumulations. The stratigraphy is so complex that seismic direct HCI evaluations are presently the only viable exploratory tool for the Frio prospect.

Proposed Program of Exploration. The Palmetto Point Project program has been completed and no further exploration wells are planned. We are assessing additional development wells in the Belmont Lake oil field discovered by the PP F-12 well. The Mississippi Frio-Wilcox Joint Venture program described below is the

successor to the Palmetto Point Program and will continue our exploration and development in the Frio and Wilcox projects.

Costs Including Previous Work. As of October 31, 2009, we have expended \$641,820 in connection with the Palmetto Point Project, including leasing, title, drilling, and casing.

Present Activities. As of October 31, 2007, Griffin & Griffin, operator of the Palmetto Point Project, drilled all ten of the wells in the Palmetto Point Project. Eight of the wells were successful and two were dry holes which were not completed. Seven of the eight successful wells were completed and are currently producing. One of the eight wells, the PP F-12, was completed as a flowing oil well in early October 2007. The PP F-12 well flowed oil at rates of over 100 Bbls per day and in December 2007 was offset by two additional wells in the project, the PP F-12-2 and PP F-12-3. The PP F-12-2 was a dry hole and the PP F-3 was completed as a flowing oil well.

Both the PP F-12 and the PP F-3 oil well locations and several of our gas well locations have been flooded at the Palmetto Point Project. Prior to the flooding, we had partly completed work to install gas lift pumps at each well; however, the work could not be completed before the locations were flooded. There has been virtually no damage to our surface equipment located at the well heads, as our batteries and other production facilities are located above the flood waters. Thus far, the only damage has been to our recent lost production because the well had to be shut-in. We do not believe that the flooding will adversely affect future oil recovery from these wells.

In early September 2008, flood waters had receded sufficiently and work began on placing the PP F-12 and PP F-12-3 back on line and producing oil. Gas lift pumps were installed on both wells and other modification and additional equipment such as compressors were also installed. At the end of October 2009, both wells were producing oil at combined rates of between 80 and 100 barrels of oil per day.

During the three-month period ended October 31, 2009, 7,265 Bbls of oil and 9,314 MCF of natural gas were produced at the Palmetto Point Project.

Mississippi Frio-Wilcox Joint Venture

Location and Access. The Mississippi Frio-Wilcox Joint Venture is located on the border of southern Mississippi and Louisiana along the floodplain of the Mississippi river. The area is approximately 20 miles west of Woodville, Mississippi and approximately 50 miles northwest of Baton Rouge, Louisiana. The wells are located in Township 2 North, Ranges 4 & 5, in West Adams and Wilkinson Counties in the state of Mississippi. The area is accessible via Interstate 55 (approximately 100 miles south of Jackson, Mississippi) and then west via state highways. The drill locations are accessed by secondary gravel and dirt roads. Transporting natural gas to the market will be accomplished via a series of pipelines which cross the project area.

Previous Operations and History. As described above, we participated in the ten-well Palmetto Point Project program in the same area as the Mississippi Frio-Wilcox Joint Venture. The Mississippi Frio-Wilcox Joint Venture is the successor to the Palmetto Point Project. Griffin & Griffin, the operator for the Palmetto Point Project, is also the operator for the Mississippi Frio-Wilcox Joint Venture. Griffin & Griffin has over 40 years of operations history in the Mississippi Frio-Wilcox Joint Venture area and has acquired substantial data and 3-D seismic for the Mississippi Frio-Wilcox Joint Venture. To date, Griffin & Griffin has drilled, owned or operated more than 100 Frio wells in the region.

Geology of the Palmetto Point Project. The prospect wells are located to test the Frio Geological Formation. The gas targets at the Mississippi Frio-Wilcox Joint Venture occur at shallow depths and have minimal completion costs. The Frio in the area of Southwest Mississippi and North-Central Louisiana is a very complex series of sand representing marine transgressions and regressions and resulting in the presence of varying depositional environments. Structurally, the Frio gas accumulations are a function of local structure and/or structural nose formed as a result of differential compaction features. However, stratigraphic termination (updip pinchout of sands within shales) also plays a role in most Frio accumulations. The stratigraphy is so complex that seismic HCI evaluations are the only viable exploratory tool for the Mississippi Frio-Wilcox Joint Venture.

Proposed Program of Exploration. On June 21, 2007, we assigned our interests and all future development obligations for any new wells in the Mississippi Frio-Wilcox Joint Venture to Lexaria for the sum of \$1. We believe the assigned interest to be of nominal value. We have maintained our original interest, rights, title and benefits to all seven wells drilled with our participation at the Mississippi Frio-Wilcox Joint Venture between August 3, 2006 and June 19, 2007, specifically wells CMR-USA-39-14, Dixon #1, Faust #1 TEC F-1, CMR/BR F-14, RB F-1 Red Bug #2, BR F-33, and Randall #1 F-4, and any offset wells that could be drilled to any of these specified wells.

Costs Including Previous Work. As of October 31, 2009, we have expended \$400,000 in connection with the Mississippi Frio-Wilcox Joint Venture, including leasing, title, drilling, and casing.

Present Activities. Nine wells were drilled on the Mississippi Frio-Wilcox Joint Venture, of which, five wells were initially deemed successful and four wells were dry holes and were not completed. One of the five wells initially deemed to be successful was the BR F-24. However, subsequent testing of the BR F-24 indicated that it was not commercially viable and the well was plugged and abandoned in 2007. The four remaining successful wells were the Faust #1, USA 39-14, USA 1-37 and the BR F-33. The USA 39-14 has been completed and is now producing natural gas. As of October 31, 2009, these four wells were shut-in natural gas wells with no production. No further exploration wells are currently planned for this project.

King City Oil Field

Late in the quarter ending July 31, 2009, we entered into an agreement with Sunset Exploration to explore for oil and gas on 10,000 acres located in west central California. The agreement calls for us to earn a 20% working interest in the project by funding a maximum of 50% of a \$200,000 geophysical survey composed of gravity and seismic surveys and agreeing to carry Sunset Exploration for 40% of dry hole cost of the first well. Completions and drilling of this first well and completion of subsequent wells on the 10,000 acres will be proportionate to each parties working interest. The geophysical surveys have already started and most have been completed. The initial surveys indicated that several more short geophysical survey lines would improve the interpretation and they will be done in the first quarter of 2010.

International Exploration Program

The Company is attempting to expand its property base by locating other resource properties internationally. Accordingly, we have hired consultants to gather data on properties that may be of interest to us. The consultants on a best efforts basis will attempt to acquire option agreements, lease agreements and/or the outright purchase of oil and /or gas properties internationally. As of the date of this filing, we have not found a suitable acquisition.

Production and Prices

The following table sets forth information regarding net production of oil and natural gas, and certain price and cost information for fiscal years ended October 31, 2009, 2008 and 2007.

	For the fiscal year ended October 31, 2009	For the fiscal year ended October 31, 2008	For the fiscal year ended October 31, 2007
Production Data:			
Natural gas (Mcf)	18,597	27,620	21,283
Oil (Bbls)	6,461	12,465	21,072
Average Prices:			
Natural gas (per Mcf)	\$2.90	\$8.52	\$3.88
Oil (per Bbl)	\$51.41	\$101.28	\$69.78
Production Costs:			
Natural gas (per Mcf)	\$1.20	\$3.24	\$3.03
Oil (per Bbl)	\$13.81	\$14.21	\$4.69

Productive Wells

The following table summarizes information at October 31, 2009, relating to the productive wells in which we owned a working interest as of that date. Productive wells consist of producing wells and wells capable of production, but specifically exclude wells drilled and cased during the fiscal year that have yet to be tested for completion (e.g., all of the operated wells drilled by the Company during this year have been cased in preparation for completion, but no operations have been initiated that would allow these wells to be productive). Gross wells are the total number of producing wells in which we have an interest, and net wells are the sum of our fractional working interests in the gross wells.

Location	Gross			Net		
	Oil	Gas	Total	Oil	Gas	Total
Oklahoma	8	0	8	0.4	0.0	0.4
Mississippi	0	0	0	0.0	0.0	0.0
Louisiana	0	0	0	0.0	0.0	0.0
Total	8	0	8	0.4	0.0	0.4

Unaudited Oil and Gas Reserve Quantities

The following unaudited reserve estimates for Oklahoma, presented as of October 31, 2009, were prepared by J L. Thomas Engineering and Harper and Associates, both independent petroleum engineering firms. The unaudited reserve estimates for Mississippi and Louisiana, as of October 31, 2009, were prepared by Veazey & Associates, an independent petroleum engineering firm.

The combined estimated proved reserves prepared by J L. Thomas Engineering, Veazey and Associates and Harper and Associates are summarized in the table below, in accordance with definitions and pricing requirements as prescribed by the Securities and Exchange Commission (the "SEC"). Prices paid for oil and natural gas vary widely depending upon the quality such as the Btu content of the natural gas, gravity of the oil, sulfur content and location of the production related to the refinery or pipelines.

There are many uncertainties inherent in estimating proved reserve quantities and in projecting future production rates and the timing of development expenditures. In addition, reserve estimates of new discoveries that have little production history are more imprecise than those of properties with more production history. Accordingly, these estimates are expected to change as future information becomes available.

Proved oil and gas reserves are the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved developed oil and gas reserves are those reserves expected to be recovered through existing wells with existing equipment and operating methods.

Unaudited net quantities of proved developed and undeveloped reserves of crude oil and natural gas (all located within United States) are as follows:

Changes in proved reserves	Crude Oil	Natural Gas
	(Bbls)	(Mcf)
Estimated quantity, October 31, 2007	115,913	145,395
Revisions of previous estimate	8,942	(16,327)
Discoveries	6,112	28,385
Reserves sold to third parties	(96,081)	(31,082)
Production	(12,465)	(27,620)
Estimated quantity, October 31, 2008	22,421	98,751
Revisions of previous estimate	9,933	(21,618)
Discoveries	30,550	14,890
Production	(6,461)	(18,597)
Estimated quantity, October 31, 2009	56,443	73,426

Proved Reserves at year end	Developed	Undeveloped	Total
Crude Oil (Bbls)			
October 31, 2009	25,773	30,670	56,443
October 31, 2008	8,781	13,640	22,421
Gas (MCF)			
October 31, 2009	62,626	10,800	73,426
October 31, 2008	98,751	-	98,751

Oil and Gas Acreage

The following table sets forth the undeveloped and developed acreage, by area, held by us as of October 31, 2009. Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas, regardless of whether or not such acreage contains proved reserves. Developed acres are acres, which are spaced or assignable to productive wells. Gross acres are the total number of acres in which we have a working interest. Net acreage is obtained by multiplying gross acreage by our working interest percentage in the properties. The table does not include acreage in which we have a contractual right to acquire or to earn through drilling projects, or any other acreage for which we have not yet received leasehold assignments.

	Undeveloped Acres		Developed Acres	
	Gross	Net	Gross	Net
Oklahoma	2,274	352.0	640	88.0
Mississippi	80	6.4	1,680	142.8
Louisiana	0	0.0	40	3.4
California	10,000	2,000.0	0	0.0
Total	12,354	2,358.4	2,360	234.2

Drilling Activity

The following table sets forth our drilling activity during the years ended October 31, 2009, 2008 and 2007.

	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Productive	8	.40	1	.400	6	0.470
Dry	3	.15	0	0	4	0.320

Development wells:						
Productive	0	0	1	.085	3	1.250
Dry	0	0	1	.085	1	0.425
Total wells	11	.55	3	.570	14	2.465

Mineral Property

Antelope Pass Project

We suspended activities on the Antelope Pass Project indefinitely in order to focus on our oil and gas properties in 2005. We have not conducted any operations or exploration activities on the Antelope Pass Project since 2005. To date, we have expended \$8,207 in connection with the Antelope Pass Project, including geological mapping, sampling and assaying.

Location and Access. The Antelope Pass Project is located in west central Hidalgo County, New Mexico, approximately ten miles east of the New Mexico-Arizona border. The Antelope Pass Project lies in the Peloncillo Mountains, 35 miles southwest of Lordsburg, New Mexico. The closest major air service to the property is located in Tucson, Arizona. Access to the property is from Tucson traveling east via Interstate Highway 10 for approximately 130 miles to the Animas, New Mexico exit. From that exit, travel is south 20 miles on State Highway 338 to the town of Animas and then west for seven miles via State Highway 9. The property can be reached on gravel roads and dirt tracks.

The property is comprised of low hills and alluvial valleys, with elevations ranging from a low of 4,480 feet to a high of 4,580 feet. Vegetation is sparse and includes desert grasses, cacti, and creosote bushes. The Antelope Pass Project consists of eight unpatented lode mining claims totaling 160 acres, situated in Township 27 South, Range 20 West, Sections 18 and 19 and Township 27 South, Range 21 West, Sections 13 and 24. A lode is a mineral deposit in consolidated rock as opposed to a placer deposit, which is a deposit of sand or gravel that contains particles of gold, ilmenite, gemstones, or other heavy minerals of value.

The claims are located on federal lands under the administration of the Bureau of Land Management (BLM). They are not subject to any royalties, but annual maintenance fees must be paid to the BLM of \$125 per claim or a total of \$1,000 for the entire claim block to keep them valid. Including federal and county filing fees, an expenditure of approximately \$125 per claim for total payment of \$1,000 per year for the entire claim block is required to keep the claims valid.

Under the General Mining Law of 1872, which governs our mining claims and leases, we, as the holder of the claim, have the right to develop the minerals located in the land identified in the claim. We must pay an annual maintenance fee of \$125 per claim to hold the claim. Claims can be held indefinitely with or without mineral production, subject to challenge if not developed. Using land under an unpatented mining claim for anything but mineral and associated purposes violates the General Mining Law of 1872.

Office Space

We are using the offices of Leroy Halterman, our president. These offices are located at 820 Piedra Vista Road NE, Albuquerque, NM 87123. We reimburse Mr. Halterman for the use of this space.

ITEM 3. LEGAL PROCEEDINGS.

None.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

None.

PART II

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

Our common stock has been listed for quotation on the OTC Bulletin Board since July 27, 2004 under the symbol "BNXR". The following table sets forth the range of high and low bid quotations for each fiscal quarter of the last two fiscal years. These quotations reflect inter-dealer prices without retail mark-up, markdown, or commissions and may not necessarily represent actual transactions.

	Bid Prices	
2008 Fiscal Year		
Quarter ending 01/31/08	\$0.26	\$0.12
Quarter ending 04/30/08	\$0.27	\$0.15
Quarter ending 07/31/08	\$0.45	\$0.17
Quarter ending 10/31/08	\$0.26	\$0.10
2009 Fiscal Year		
Quarter ending 01/31/09	\$0.21	\$0.06
Quarter ending 04/30/09	\$0.17	\$0.055
Quarter ending 07/31/09	\$0.13	\$0.04
Quarter ending 10/31/09	\$0.135	\$0.04

As of January 20, 2010, there were 39 record holders of our common stock. The closing bid price of our stock on January 15, 2010 was \$0.15.

Since our inception, no cash dividends have been declared on our common stock.

We had no sales of unregistered securities during the quarter ended October 31, 2009.

ITEM 6. SELECTED FINANCIAL DATA.

Not required for smaller reporting companies.

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

Our original business plan was to proceed with the exploration of the Antelope Pass Project to determine whether there were commercially exploitable reserves of gold located on the property comprising the mineral claims. Based on the geological report and recommendation prepared by Leroy Halterman, who was our geological consultant at that time, we completed geological mapping, sampling and assaying in connection with the first phase of a staged exploration program during the fiscal year ended October 31, 2004. In 2005, we suspended our activities on the Antelope Pass Project indefinitely in order to focus on our oil and gas properties and we did not conduct any operations or exploration activities on the Antelope Pass Project during the fiscal years ended October 31, 2009 or 2008. At the time of this report, we do not know when or if we will proceed with the Antelope Pass Project.

Our present plan of operation is to continue our exploration and production activities on our oil and gas properties. We anticipate that we will incur the following expenses over the next twelve months in connection with our oil and gas properties:

- \$620,000 to \$1,120,000 in connection with our oil and gas properties to include drilling, completing and equipping new wells and for costs associated with production;

- \$500,000 for operating expenses, including professional legal and accounting expenses associated with our being a reporting issuer under the Securities Exchange Act of 1934.

Accordingly, we anticipate spending approximately \$1,120,000 to \$1,620,000 over the next twelve months in pursuing our stated plan of operations. The Company expects new wells to come online, generating sufficient cash to offset any increase in expenses.

Critical Accounting Policies

Oil and Gas Interests. We utilize the full cost method of accounting for oil and gas activities. Under this method, subject to a limitation based on estimated value, all costs associated with property acquisition, exploration and development, including costs of unsuccessful exploration, are capitalized within a cost center. No gain or loss is recognized upon the sale or abandonment of undeveloped or producing oil and gas interests unless the sale represents a significant portion of oil and gas interests and the gain significantly alters the relationship between capitalized costs and proved oil and gas reserves of the cost center. Depreciation, depletion and amortization of oil and gas interests is computed on the units of production method based on proved reserves, or upon reasonable estimates where proved reserves have not yet been established due to the recent commencement of production. Amortizable costs include estimates of future development costs of proved undeveloped reserves.

Capitalized costs of oil and gas interests may not exceed an amount equal to the present value, discounted at 10%, of the estimated future net cash flows from proved oil and gas reserves plus the cost, or estimated fair market value, if lower, of unproved interests. Should capitalized costs exceed this ceiling, an impairment is recognized. The present value of estimated future net cash flows is computed by applying year end prices of oil and gas to estimated future production of proved oil and gas reserves as of year end, less estimated future expenditures to be incurred in developing and producing the proved reserves and assuming continuation of existing economic conditions.

Accounts Receivable. Accounts receivable are carried at net receivable amounts less an estimate for doubtful accounts. We determine the allowance for doubtful accounts by regularly evaluating individual customer receivables and considering a customer's financial condition, credit history, and current economic conditions. Trade receivables are written off when deemed uncollectible. Recoveries of receivables previously written off are recorded when received.

Asset Retirement Obligations. We follow FASB ASC 410-20 "Accounting for Asset Retirement Obligations". FASB ASC 410-20 addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. FASB ASC 410-20 requires recognition of the present value of obligations associated with the retirement of tangible long-lived assets in the period in which it is incurred. As of October 31, 2009 and 2008, we recognized the future cost to plug and abandon the gas wells over the estimated useful lives of the wells in accordance with FASB ASC 410-20. The liability for the fair value of an asset retirement obligation with a corresponding increase in the carrying value of the related long-lived asset is recorded at the time a well is completed and ready for production. We amortize the amount added to the oil and gas properties and recognize accretion expense in connection with the discounted liability over the remaining life of the respective wells. The estimated liability is based on historical experience in plugging and abandoning wells, estimated useful lives based on engineering studies, external estimates as to the cost to plug and abandon wells in the future and federal and state regulatory requirements. The liability is a discounted liability using a credit-adjusted risk-free rate of 12%. Revisions to the liability could occur due to changes in plugging and abandonment costs, well useful lives or if federal or state regulators enact new guidance on the plugging and abandonment of wells.

The information below reflects the change in the asset retirement obligations during the years ended October 31, 2009 and 2008:

	October 31, 2009	October 31, 2008
Balance, beginning of year	\$ 30,766	\$ 34,584
Liabilities assumed	9,206	3,376
Revisions	(6,653)	(11,344)
Accretion expense	3,692	4,150
Balance, end of year	<u>\$ 37,011</u>	<u>\$ 30,766</u>

The reclamation obligation relates to the Kodesh, Dye Estate, KC 80 and William wells at the Three Sands Property; the Palmetto Point Project well at the Frio-Wilcox Project; and ARD#1-36, Bagwell#1-20, Selman#1-21 and Selman#2-21 wells at the Oklahoma Properties. The present value of the reclamation liability may be subject to change based on management's current estimates, changes in remediation technology or changes to the applicable laws and regulations. Such changes will be recorded in our accounts as they occur.

Reserve Estimates. Our estimates of oil and natural gas reserves are projections based on an interpretation of geological and engineering data. There are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on the risk of recovery, and estimates of the future net cash flows expected therefrom may vary substantially. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material.

Share Based Compensation. In December 2004, FASB ASC 718 (Prior Authoritative Literature: SFAS 123R) *Accounting for Stock-Based Compensation* was issued. This standard defines a fair value based method of accounting for an employee stock option or similar equity instrument. This statement requires entities to recognize related compensation expense to employees by adopting the fair value method.

Results of Operations

We realized revenues of \$398,274 from natural gas and oil sales during the fiscal year ended October 31, 2009, compared with \$1,497,908 during the fiscal year ended October 31, 2008, a decrease of \$1,099,634 due to the sale of our Owl Creek Project working interests in fiscal 2008. We also generated revenues of \$1,982,293 from the gain on the sale of our Owl Creek Project, resulting in total revenues of \$3,480,201 for fiscal 2008.

For the fiscal year ended October 31, 2009, we incurred a net loss of \$377,866, compared with net income of \$2,130,151 for the fiscal year ended October 31, 2008 (a decrease in net income of \$2,508,016).

We incurred direct costs of \$1,024,206 for the fiscal year ended October 31, 2009, compared with \$998,467 for the fiscal year ended October 31, 2008, an increase of \$25,739. The increase in our direct costs was largely attributable to an increase in our general and administrative costs. Our general and administrative costs increased to \$720,391 for the fiscal year ended October 31, 2009, from \$440,191 for the fiscal year ended October 31, 2008. The increase in our general and administrative costs were attributable to an increase in fees for consulting and investor relations services and increases in management fees and costs of administration services.

Our depletion and accretion costs decreased from \$291,585 during the fiscal year ended October 31, 2008 to \$190,046 for the fiscal year ended October 31, 2009, a decrease of \$101,539. Depletion is calculated based on production rates produced during the year. Our depletion and accretion costs decreased as a result of a decrease in our oil and gas producing wells.

Our production costs also decreased from \$266,691 for the fiscal year ended October 31, 2008 to \$113,769 for the fiscal year ended October 31, 2009, a decrease of \$152,922. The decrease in our production costs was due to decreases in both the amounts of oil and gas produced, as well as a decrease in costs.

Our retained earnings through October 31, 2009 were \$1,268,676.

Liquidity and Capital Resources

As of October 31, 2009, we had cash of \$1,947,950 and working capital of \$2,494,387, compared to cash of \$3,617,109 and working capital of \$3,350,516 as of October 31, 2008.

During the fiscal year ended October 31, 2009, net cash used in operating activities was \$1,000,714, compared to cash of \$818,172 provided by operating activities for the fiscal year ended October 31, 2008.

Net cash used in investing activities during the fiscal year ended October 31, 2009 was \$668,446, compared with \$2,777,394 provided during the fiscal year ended October 31, 2008. While we used \$668,446 for oil and gas interests in fiscal 2009, we received proceeds of \$3,068,544 from the sale of our working interests in the Owl Creek Project in fiscal 2008.

We used cash of \$20,714 for the repayment of loans to related parties during the fiscal year ended October 31, 2008. No cash was provided by or used in financing activities during the fiscal year ended October 31, 2009.

Recent Accounting Pronouncements.

In May 2009, the Financial Accounting Standards Board (“FASB”) issued FASB ASC 855-10 (Prior authoritative literature: SFAS No. 165, *Subsequent Events*). FASB ASC 855-10 establishes principles and requirements for the reporting of events or transactions that occur after the balance sheet date, but before financial statements are issued or are available to be issued. FASB ASC 855-10 is effective for financial statements issued for fiscal years and interim periods ending after June 15, 2009. As such, we adopted these provisions at the beginning of the interim period ended July 31, 2009. Adoption of FASB ASC 855-10 did not have a material effect on our financial statements.

In June 2009, the FASB ASC 860-10 (Prior authoritative literature: issued SFAS No. 166, “*Accounting for Transfers of Financial Assets, an Amendment of FASB Statement No. 140*”), which eliminates the concept of a qualifying special-purpose entity (“QSPE”), clarifies and amends the de-recognition criteria for a transfer to be accounted for as a sale, amends and clarifies the unit of account eligible for sale accounting and requires that a transferor initially measure at fair value and recognize all assets obtained and liabilities incurred as a result of a transfer of an entire financial asset or group of financial assets accounted for as a sale. This standard is effective for fiscal years beginning after November 15, 2009. We are currently evaluating the potential impact of this standard on its financial statements, but do not expect it to have a material effect.

In June 2009, the FASB issued FASB ASC 810-10-65 (Prior authoritative literature: SFAS No. 167, “*Amendments to FASB Interpretation No. 46(R)*”) which amends the consolidation guidance applicable to a variable interest entity (“VIE”). This standard also amends the guidance governing the determination of whether an enterprise is the primary beneficiary of a VIE, and is therefore required to consolidate an entity, by requiring a qualitative analysis rather than a quantitative analysis. Previously, the standard required reconsideration of whether an enterprise was the primary beneficiary of a VIE only when specific events had occurred. This standard is effective for fiscal years beginning after November 15, 2009, and for interim periods within those fiscal years. Early adoption is prohibited. We are currently evaluating the potential impact of the adoption of this standard on its financial statements, but do not expect it to have a material effect.

In June 2009, FASB issued ASC 105-10 (Prior authoritative literature: SFAS No. 168, *The FASB Accounting Standards Codification TM and the Hierarchy of Generally Accepted Accounting Principles - a replacement of FASB Statement No. 162*). FASB ASC 105-10 establishes the FASB Accounting Standards Codification TM (Codification) as the source of authoritative accounting principles recognized by the FASB to be applied by nongovernmental entities in the preparation of financial statements in conformity with GAAP. FASB ASC 105-10 is effective for financial statements issued for fiscal years and interim periods ending after September 15, 2009. As such, we are required to adopt these provisions at the beginning of the fiscal year ending September 30, 2009. Adoption of FASB ASC 105-10 did not have a material effect on our financial statements.

Off-Balance Sheet Arrangements

We did not have any off-balance sheet arrangements as of October 31, 2009.

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

Not required for smaller reporting companies.

ITEM 8. FINANCIAL STATEMENTS.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors
Brinx Resources Ltd.
Albuquerque, New Mexico

We have audited the accompanying balance sheets of Brinx Resources Ltd. (the “company”) as of October 31, 2009 and 2008 and the related statements of operations, stockholders' equity (deficit) and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audit in accordance with the standards of the Public Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal controls over financial reporting. Our audit 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 includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Brinx Resources Ltd. as of October 31, 2009 and 2008 and the results of its operations and its cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

/s/ Chisholm, Bierwolf, Nilson & Morrill, LLC

Chisholm, Bierwolf, Nilson & Morrill, LLC
Bountiful, Utah
January 28, 2010

BRINX RESOURCES LTD.
BALANCE SHEETS

	<u>OCTOBER 31</u> <u>2009</u>	<u>OCTOBER 31</u> <u>2008</u> (Restated)
ASSETS		
Current assets		
Cash and cash equivalents	\$ 1,947,950	\$ 3,617,109
Accounts receivable	97,198	71,377
Income taxes receivable	253,814	-
Prepaid expenses and deposit	<u>270,610</u>	<u>15,808</u>
Total current assets	2,569,572	3,704,294
Undeveloped mineral interests, at cost	811	811
Oil and gas interests, full cost method of accounting, net of accumulated depletion	<u>1,637,010</u>	<u>1,152,365</u>
Total assets	<u>\$ 4,207,393</u>	<u>\$ 4,857,470</u>
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	\$ 75,185	\$ 2,404
Income taxes payable	<u>-</u>	<u>351,374</u>
Total current liabilities	75,185	353,778
Deferred income taxes	-	-
Asset retirement obligations	<u>37,011</u>	<u>30,766</u>
Total liabilities	<u>112,196</u>	<u>384,544</u>
Commitments and contingencies		
Stockholders' equity		
Preferred stock - \$0.001 par value; authorized - 25,000,000 shares Issued - none	-	-
Common stock - \$0.001 par value; authorized - 100,000,000 shares Issued and outstanding - 24,529,832 shares	24,530	24,530
Capital in excess of par value	2,801,991	2,801,855
Retained earnings	<u>1,268,676</u>	<u>1,646,541</u>
Total stockholders' equity	<u>4,095,197</u>	<u>4,472,926</u>
Total liabilities and stockholders' equity	<u>\$ 4,207,393</u>	<u>\$ 4,857,470</u>

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

BRINX RESOURCES LTD.
STATEMENTS OF OPERATIONS

	<u>YEAR ENDED OCTOBER 31 2009</u>	<u>YEAR ENDED OCTOBER 31 2008</u> (Restated)
REVENUES		
Natural gas and oil sales	\$ 398,274	\$ 1,497,908
Gain on sale of natural gas and oil interests	<u>-</u>	<u>1,982,293</u>
	<u>398,274</u>	<u>3,480,201</u>
DIRECT COSTS		
Production costs	113,769	266,691
Depletion and accretion	190,046	291,585
General and administrative	<u>720,391</u>	<u>440,191</u>
Total Expenses	<u>(1,024,206)</u>	<u>(998,467)</u>
OPERATING INCOME (LOSS)	(625,932)	2,481,734
OTHER INCOME AND EXPENSE		
Interest income	1,291	-
Interest expense - related	<u>-</u>	<u>(209)</u>
NET INCOME (LOSS) BEFORE INCOME TAXES	(624,641)	2,481,525
Recovery of income taxes	(246,775)	-
Provision for income taxes	<u>-</u>	<u>351,374</u>
NET INCOME (LOSS) FOR THE PERIODS	\$ (377,866)	\$ 2,130,151
Net Income Per Common Share		
- Basic	<u>\$ (0.02)</u>	<u>\$ 0.09</u>
- Diluted	<u>\$ (0.02)</u>	<u>\$ 0.09</u>
Weighted average number of common shares outstanding		
- Basic	<u>24,529,832</u>	<u>24,529,832</u>
- Diluted	<u>24,529,832</u>	<u>24,529,832</u>

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

BRINX RESOURCES LTD.
STATEMENT OF STOCKHOLDERS' EQUITY

	<u>PREFERRED STOCK</u>		<u>COMMON STOCK</u>		<u>Capital in Excess of Par Value</u>	<u>Retained Earnings/ (Deficit)</u>	<u>Total Shareholder's Equity</u>
	<u>Number of Shares</u>	<u>Amount</u>	<u>Number of Shares</u>	<u>Amount</u>			
BALANCES, OCTOBER 31, 2007	-	-	24,529,832	24,530	2,775,778	(483,610)	2,316,698
Valuation of stock options (Note 6)	-	-	-	-	26,077	-	26,077
Net income (Restated)	-	-	-	-	-	<u>2,130,151</u>	<u>2,130,151</u>
BALANCES, OCTOBER 31, 2008 (Restated)	-	-	24,529,832	24,530	2,801,855	1,646,541	4,472,926
Valuation of stock options (Note 6)	-	-	-	-	136	-	136
Net (loss)	-	-	-	-	-	<u>(377,866)</u>	<u>(377,866)</u>
BALANCES, October 31, 2009	-	<u>\$ -</u>	<u>24,529,832</u>	<u>\$ 24,530</u>	<u>\$ 2,801,991</u>	<u>\$ 1,268,675</u>	<u>\$ 4,095,196</u>

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

BRINX RESOURCES LTD.
STATEMENTS OF CASH FLOWS

	<u>YEAR ENDED OCTOBER 31 2009</u>	<u>YEAR ENDED OCTOBER 31 2008</u> (Restated)
CASH FLOWS PROVIDED BY (USED IN) OPERATING ACTIVITIES		
Net income (loss)	\$ (377,866)	\$ 2,130,151
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Stock based compensation (note 6)	136	26,077
Gain on sale of natural gas and oil interests	-	(1,982,293)
Depletion and accretion	190,046	291,585
Changes in working capital:		
Decrease (Increase) in accounts receivable	(25,821)	210,123
Decrease (Increase) in prepaid expenses and deposit	(254,802)	(15,808)
Increase (Decrease) in accounts payable and accrued liabilities	72,781	(192,075)
Increase (Decrease) in income taxes receivable	(253,814)	-
Interest accrued to related party notes	-	209
Increase (Decrease) in due to related party	-	(1,171)
Increase (Decrease) in income taxes payable	(351,374)	351,374
	<u>(1,000,714)</u>	<u>818,172</u>
Net cash provided by (used in) operating activities		
CASH FLOWS PROVIDED BY (USED IN) INVESTING ACTIVITIES		
Payments on oil and gas interests	(668,446)	(291,150)
Proceeds from sale of natural gas and oil interests	-	3,068,544
	<u>(668,446)</u>	<u>2,777,394</u>
Net cash provided by (used in) investing activities		
CASH FLOWS PROVIDED BY (USED IN) FINANCING ACTIVITIES		
Repayment of loan to related party	-	(20,714)
	<u>-</u>	<u>(20,714)</u>
Net cash (used in) financing activities		
	<u>(1,669,160)</u>	<u>3,574,852</u>
Net increase (decrease) in cash		
	<u>3,617,109</u>	<u>42,257</u>
Cash and cash equivalents, beginning of periods		
	<u>\$ 1,947,949</u>	<u>\$ 3,617,109</u>
Cash and cash equivalents, end of periods		
SUPPLEMENTAL CASH FLOW INFORMATION		
Cash paid for taxes paid	\$ 580,000	\$ -
Cash paid for interest	\$ -	\$ (209)
SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES		
Assets retirement costs incurred	\$ (3,692)	\$ 7,968
Investment in natural oil and gas working interests included in accounts payable	\$ 54,023	\$ -

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

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Brinx Resources Ltd. (the "Company") was incorporated under the laws of the State of Nevada on December 23, 1998, and issued its initial common stock in February 2001. The Company holds undeveloped mineral interest located in New Mexico and holds oil and gas interests located in Oklahoma, Mississippi and Louisiana. In 2006, the Company commenced oil and gas production and started earning revenues. Prior to 2006, the Company was considered a development stage company as defined by FASB ASC 915 (prior authoritative literature: SFAS No. 7), effective 2006, the Company ceased being considered a development stage company.

USE OF ESTIMATES

The preparation of financial statement in conformity with generally accepted accounting principles 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 reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

The oil and gas industry is subject, by its nature, to environmental hazards and clean-up costs. At this time, management knows of no substantial costs from environmental accidents or events for which the Company may be currently liable. In addition, the Company's oil and gas business makes it vulnerable to changes in prices of crude oil and natural gas. Such prices have been volatile in the past and can be expected to be volatile in the future. By definition, proved reserves are based on current oil and gas prices and estimated reserves. Price declines reduce the estimated quantity of proved reserves and increase annual depletion expense (which is based on proved reserves).

OIL AND GAS INTERESTS

The Company utilizes the full cost method of accounting for oil and gas activities. Under this method, subject to a limitation based on estimated value, all costs associated with property acquisition, exploration and development, including costs of unsuccessful exploration; are capitalized within a cost center. No gain or loss is recognized upon the sale or abandonment of undeveloped or producing oil and gas interests unless the sale represents a significant portion of oil and gas interests and the gain significantly alters the relationship between capitalized costs and proved oil and gas reserves of the cost center. Depreciation, depletion and amortization of oil and gas interests is computed on the units of production method based on proved reserves, or upon reasonable estimates where proved reserves have not yet been established due to the recent commencement of production. Amortizable costs include estimates of future development costs of proved undeveloped reserves.

Capitalized costs of oil and gas interests may not exceed an amount equal to the present value, discounted at 10%, of the estimated future net cash flows from proved oil and gas reserves plus the cost, or estimated fair market value, if lower, of unproved interests. Should capitalized costs exceed this ceiling, an impairment is recognized. The present value of estimated future net cash flows is computed by applying year end prices of oil and gas to estimated future production of proved oil and gas reserves as of year end, less estimated future expenditures to be incurred in developing and producing the proved reserves and assuming continuation of existing economic conditions.

REVENUE RECOGNITION

Revenue from sales of crude oil, natural gas and refined petroleum products are recorded when deliveries have occurred and legal ownership of the commodity transfers to the customers. Title transfers for crude oil, natural gas and bulk refined products generally occur at pipeline custody points or when a tanker lifting has occurred. Revenues from the production of oil and natural gas properties in which the Company shares an undivided interest with other producers are recognized based on the actual volumes sold by the Company during the period. Gas imbalances occur when the Company's actual sales differ from its entitlement under existing working interests. The Company records a liability for gas imbalances when it

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

REVENUE RECOGNITION (continued)

has sold more than its working interest of gas production and the estimated remaining reserves make it doubtful that the partners can recoup their share of production from the field. At October 31, 2009 and 2008, the Company had no overproduced imbalances.

ACCOUNTS RECEIVABLE

Accounts receivable are carried at net receivable amounts less an estimate for doubtful accounts. Management determines the allowance for doubtful accounts by regularly evaluating individual customer receivables and considering a customer's financial condition, credit history, and current economic conditions. Trade receivables are written off when deemed uncollectible. Recoveries of receivables previously written off are recorded when received.

IMPAIRMENT OF LONG-LIVED ASSETS

The Company has adopted FASB ASC 360 (prior authoritative literature: SFAS No. 144) *Accounting for the Impairment or Disposal of Long-Lived Assets*, which requires that long-lived assets to be held and used be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Oil and gas interests accounted for under the full cost method are subject to a ceiling test, described above, and are excluded from this requirement.

ASSET RETIREMENT OBLIGATIONS

The Company follows FASB ASC 410-20 (prior authoritative literature: SFAS No. 143) *Accounting for Asset Retirement Obligations*, that addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs.

FASB ASC 410-20 requires recognition of the present value of obligations associated with the retirement of tangible long-lived assets in the period in which it is incurred. The liability is capitalized as part of the related long-lived asset's carrying amount.

Over time, accretion of the liability is recognized as an operating expense and the capitalized cost is depreciated over the expected useful life of the related asset. The Company's asset retirement obligations are related to the plugging, dismantlement, removal, site reclamation and similar activities of its oil and gas exploration activities.

INCOME / (LOSS) PER SHARE

Basic income/ (loss) per share is computed based on the weighted average number of common shares outstanding during each period. The computation of diluted earnings per share assumes the conversion, exercise or contingent issuance of securities only when such conversion, exercise or issuance would have the dilutive effect on income/ (loss) per share. The dilutive effect of convertible securities is reflected in diluted earnings per share by application of the "as if converted method." The dilutive effect of outstanding options and warrants and their equivalents is reflected in diluted earnings per share by application of the treasury stock method. Hence 400,000 options were excluded from the earnings per share calculation for the year ended October 31, 2009, since they were considered to be anti-dilutive. The table below presents the computation of basic and diluted earnings per share for the years ended October 31, 2009 and 2008:

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

INCOME / (LOSS) PER SHARE (continued)

	October 31, 2009	October 31, 2008 (Restated)
Basic earnings per share computation:		
Income (Loss) from continuing operations and net income	\$ (377,866)	\$ 2,130,151
Basic shares outstanding	24,529,832	24,529,832
Basic earnings per share	\$ (0.02)	\$ 0.09
Diluted earnings per share computation:		
Income (Loss) from continuing operations	\$ (377,866)	\$ 2,130,151
Basic shares outstanding	24,529,832	24,529,832
Incremental shares from assumed conversions:		
Stock options	-	-
Warrants	-	-
Diluted shares outstanding	24,529,832	24,529,832
Diluted earnings per share	\$ (0.02)	\$ 0.09

The calculation for earnings per share excluded 400,000 stock options and 200,000 stock options as these were not in the money as at October 31, 2009 and October 31, 2008, respectively.

INCOME TAXES

Deferred tax assets and liabilities are recognized for temporary differences between the financial reporting and tax bases of the firm's assets and liabilities. Valuation allowances are established to reduce deferred tax assets to the amount that more likely than not will be realized. The firm's tax assets and liabilities are presented as a component of "Other assets" and "Other liabilities and accrued expenses," respectively, in the consolidated statements of financial condition. Tax provisions are computed in accordance with FASB ASC 740 (prior authoritative literature: SFAS No. 109), "Accounting for Income Taxes".

The firm adopted the provisions of FASB ASC 740-10 "Accounting for Uncertainty in Income Taxes — an Interpretation", as of December 1, 2007. A tax position can be recognized in the financial statements only when it is more likely than not that the position will be sustained upon examination by the relevant taxing authority based on the technical merits of the position. A position that meets this standard is measured at the largest amount of benefit that will more likely than not be realized upon settlement. A liability is established for differences between positions taken in a tax return and amounts recognized in the financial statements. FASB ASC 740-10 also provides guidance on derecognition, classification, interim period accounting and accounting for interest and penalties. Prior to the adoption of this policy, contingent liabilities related to income taxes were recorded when the criteria for loss recognition had been met.

CASH EQUIVALENTS

For purposes of reporting cash flows, the Company considers as cash equivalents all highly liquid investments with a maturity of three months or less at the time of purchase. On occasion, the Company may have cash balances in excess of federally insured amounts.

FAIR VALUE

On January 1, 2008, the Company adopted FASB ASC 820-10-50, "Fair Value Measurements". This guidance defines fair value, establishes a three-level valuation hierarchy for disclosures of fair value measurement and enhances disclosure requirements for fair value measures. The three levels are defined as follows:

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

FAIR VALUE (continued)

- Level 1 inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3 inputs to valuation methodology are unobservable and significant to the fair measurement.

The carrying amounts reported in the balance sheets for the cash and cash equivalents, receivables and current liabilities each qualify as financial instruments and are a reasonable estimate of fair value because of the short period of time between the origination of such instruments and their expected realization and their current market rate of interest.

CONCENTRATION OF CREDIT RISK

Financial instruments which potentially subject the Company to concentrations of credit risk consist of cash and cash equivalents and accounts receivable. The Company maintains cash at one financial institution. The Company periodically evaluates the credit worthiness of financial institutions, and maintains cash accounts only in large high quality financial institutions, thereby minimizing exposure for deposits in excess of federally insured amounts. The Company believes credit risk associated with cash and cash equivalents to be minimal, however, the at risk amounts for the year ended October 31, 2009 were \$1,697,950 and \$3,367,109 for the year ended October 31, 2008.

The Company has recorded trade accounts receivable from the business operations. Management periodically evaluates the collectability of the trade receivables and believes that the Company's receivables are fully collectable and that the risk of loss is minimal.

COMPREHENSIVE INCOME

There are no adjustments necessary to net (loss) as presented in the accompanying statements of operations to derive comprehensive income in accordance with FASB ASC 220-10 (prior authoritative literature: SFAS No. 130), *Reporting Comprehensive Income*."

EQUITY BASED COMPENSATION

Effective November 1 2006, the Company adopted the fair value recognition provisions of FASB ASC 718 (prior authoritative literature: SFAS No. 123R) "*Share Based Payment*" using the modified prospective method as described in "*Accounting for Stock-Based Compensation – Transition and Disclosure*", as prescribed by the United States Securities and Exchange Commission ("SEC").

The fair value of each option granted has been estimated as of the date of the grant using the Black-Scholes option pricing model with the following assumptions:

	Years ended October 31, 2009	Years ended October 31, 2008
Expected volatility	149%	100.36%
Risk-free interest rate	0.11%	4.50%
Expected life	2 years	2 years
Dividend yield	0.00%	0.00%

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

RECENT ACCOUNTING PRONOUNCEMENTS

In May 2009, FASB issued FASB ASC 855-10 (Prior authoritative literature: SFAS No. 165, *Subsequent Events*). FASB ASC 855-10 establishes principles and requirements for the reporting of events or transactions that occur after the balance sheet date, but before financial statements are issued or are available to be issued. FASB ASC 855-10 is effective for financial statements issued for fiscal years and interim periods ending after June 15, 2009. As such, the Company adopted these provisions at the beginning of the interim period ended July 31, 2009. Adoption of FASB ASC 855-10 did not have a material effect on our financial statements.

In June 2009, the FASB ASC 860-10 (Prior authoritative literature: issued SFAS No. 166, “*Accounting for Transfers of Financial Assets, an Amendment of FASB Statement No. 140*”), which eliminates the concept of a qualifying special-purpose entity (“QSPE”), clarifies and amends the de-recognition criteria for a transfer to be accounted for as a sale, amends and clarifies the unit of account eligible for sale accounting and requires that a transferor initially measure at fair value and recognize all assets obtained and liabilities incurred as a result of a transfer of an entire financial asset or group of financial assets accounted for as a sale. This standard is effective for fiscal years beginning after November 15, 2009. The Company is currently evaluating the potential impact of this standard on its financial statements, but does not expect it to have a material effect.

In June 2009, the FASB issued FASB ASC 810-10-65 (Prior authoritative literature: SFAS No. 167, “*Amendments to FASB Interpretation No. 46(R)*”) which amends the consolidation guidance applicable to a variable interest entity (“VIE”). This standard also amends the guidance governing the determination of whether an enterprise is the primary beneficiary of a VIE, and is therefore required to consolidate an entity, by requiring a qualitative analysis rather than a quantitative analysis. Previously, the standard required reconsideration of whether an enterprise was the primary beneficiary of a VIE only when specific events had occurred. This standard is effective for fiscal years beginning after November 15, 2009, and for interim periods within those fiscal years. Early adoption is prohibited. The Company is currently evaluating the potential impact of the adoption of this standard on its financial statements, but does not expect it to have a material effect.

In June 2009, FASB issued ASC 105-10 (Prior authoritative literature: SFAS No. 168, *The FASB Accounting Standards Codification TM and the Hierarchy of Generally Accepted Accounting Principles - a replacement of FASB Statement No. 162*). FASB ASC 105-10 establishes the FASB Accounting Standards Codification TM (Codification) as the source of authoritative accounting principles recognized by the FASB to be applied by nongovernmental entities in the preparation of financial statements in conformity with GAAP. FASB ASC 105-10 is effective for financial statements issued for fiscal years and interim periods ending after September 15, 2009. As such, the Company is required to adopt these provisions at the beginning of the fiscal year ending October 31, 2009. Adoption of FASB ASC 105-10 did not have a material effect on the Company’s financial statements.

2. ACCOUNTS RECEIVABLE

Accounts receivable consists of revenues receivable from the operators of the oil and gas projects for the sale of oil and gas by the operators on their behalf and are carried at net receivable amounts less an estimate for doubtful accounts. Management considers all accounts receivable to be fully collectible at October 31, 2009 and October 31, 2008. Accordingly, no allowance for doubtful accounts or bad debt expense has been recorded.

	October 31, 2009	October 31, 2008
Accounts receivable	\$ 97,198	\$ 71,377
Less: allowance for doubtful account	-	-
	<u>\$ 97,198</u>	<u>\$ 71,377</u>

3. OIL AND GAS INTERESTS

The Company holds the following oil and natural gas interests:

	October 31, 2009	October 31, 2008
2008-3 Drilling Program, Oklahoma	\$ 258,980	\$ -
2009-2 Drilling Program, Oklahoma	82,935	-
2009-3 Drilling Program, Oklahoma	137,356	-
King City Prospect, California	100,000	-
Three Sands Project, Oklahoma	1,197,523	1,196,600
Palmetto Point Project, Mississippi	420,000	420,000
Frio-Wilcox Prospect, Mississippi	400,000	400,000
PP F-12-2, PP F-12-3, PP F-12-4 and PP F-52, Mississippi	221,820	133,568
Asset retirement cost	22,949	20,396
Less: Accumulated depletion and impairment	(1,204,553)	(1,018,199)
	<u>\$ 1,637,010</u>	<u>\$ 1,152,365</u>

2008-3 Drilling Program, Oklahoma

On January 12, 2009, the Company acquired a 5% working interest in the Ranken Energy Corporation's 2008-3 Drilling Program for a total buy-in cost of \$28,581.25. The Company agreed to participate in the drilling operations to casing point in the initial test well of each prospect. The Before Casing Point Interest "BCP" shall be 6.25% and the After Casing Point Interest "ACP" shall be 5.00%. During January to July 2009, the Company expended an additional \$213,925. The total cost of the 2008-3 Drilling Program as at July 31, 2009 was \$242,506. The well, Wigley #1-11, was abandoned on March 2009, and the cost of \$23,510 was moved to the proved properties. Selman #1-21 and Bagwell #1-20 started producing on May 2009, Ard #1-36 started producing on June 2009, and Selman #2-21 started producing on July 2009. The interests are located in Garvin County, Oklahoma.

2009-2 Drilling Program, Oklahoma

On June 19, 2009, the Company acquired a 5% working interest in the Ranken Energy Corporation's 2009-2 Drilling Program for a total buy-in cost of \$26,562.50. The Company agreed to participate in the drilling operations to casing point in the initial test well of each prospect. The Before Casing Point Interest "BCP" shall be 6.25% and the After Casing Point Interest "ACP" shall be 5.00%. The well, James #1-18, was abandoned on September 21, 2009. The cost of \$33,663 was moved to the proved properties. The interests are located in Garvin County, Oklahoma.

2009-3 Drilling Program, Oklahoma

On August 12, 2009, the Company acquired a 5.00% working interest in Ranken Energy Corporation's 2009-3 Drilling Program for a total buy-in cost of \$37,775. The Company agreed to participate in the drilling operations to casing point in the initial test well of each prospect. The Before Casing Point Interest, "BCP", shall be 6.25% and the After Casing Point Interest, "ACP", shall be 5.00%. The total costs, including drilling costs, for the year ended October 31, 2009 are \$137,356.

King City Prospect, California

A Farmout agreement was made effective on May 25, 2009 between the Company and Sunset Exploration, Inc., to explore for oil and natural gas on 10,000 acres located in west central California. The Company paid \$100,000 (50% pro rata share of \$200,000) to earn a 20% working interest in project by funding a maximum of 50% of a \$200,000 in a geophysical survey composed of gravity and seismic surveys and carry Sunset exploration for 40% of dry hole cost of the first well. Completions and drilling of this first well and completion of subsequent wells on the 10,000 acres will be proportionate to each parties working interest.

3. OIL AND GAS INTERESTS (continued)

Three Sands Project, Oklahoma

On October 6, 2005, the Company acquired a 40% working interest in Vector Exploration Inc.'s Three Sands Project for a total buy-in cost of \$88,000 plus dry hole costs. For the year ended October 31, 2006, the Company expended \$530,081 in exploration costs. In June 2007, the Company acquired a 40% working interest in William #4-10 well for a total cost of \$285,196 and paid a further \$17,000 in costs relating to the well. On March 19, 2008, the Company participated in the KC 80#1-11 well and paid \$75,000 for the prepaid drilling costs. During March and April 2008, the Company expended an additional amount of \$48,763 for the intangible and tangible costs, and \$161,650 during May to July 2008 for the KC 80#1-11 well. The total cost of the Three Sands Project as at October 31, 2009 was \$1,197,523. The interests are located in Oklahoma.

Palmetto Point Project, Mississippi

On February 28, 2006, the Company acquired a 10% working interest before production and 8.5% revenue interest after production in a 10 well program at Griffin & Griffin Exploration Inc.'s Palmetto Point Project for a total buy-in cost of \$350,000. On September 26, 2006, the Company acquired an additional two wells within this program for \$70,000. On October 1, 2007, the Company acquired a 10% working interest and participated in drilling two more wells within the Palmetto Point Project, the (PP F-12-2 and PP F-12-3 wells), at a cost of \$69,862. On October 25, 2007, the Company paid \$17,000 for a sidetrack, a deviation of the existing PP-F-12-3 well at an angle to reach additional targeted oil sands.

On January 30, 2008, the Company incurred \$36,498 for workovers to install submersible pumps and subsequently paid on February 1, 2008. During November 2008 to July 2009, the Company incurred \$44,623 for Belmont Lake Project. The total cost of the Palmetto Point Project, to include costs for the PP F-12-2, PP F-12-3, PP F-12-4 and PP F-52 wells, is \$641,820 as of October 31, 2009. The interests are located in Mississippi.

Frio-Wilcox Project, Mississippi

On August 2, 2006, the Company signed a memorandum agreement with Griffin & Griffin LLC (the "Operator") to participate in two proposed drilling programs located in Mississippi and Louisiana. The Company acquired a 10% working interest in this project before production and a prorated reduced working interest after production based on the Operator's interest portion. The Company paid \$400,000 for the interest.

On June 21, 2007, the Company assigned all future development obligations for any new wells at its Frio-Wilcox Prospect to a third party. The Company maintained its original interest, rights, title and benefits to all seven wells drilled with the Company's participation at the Frio-Wilcox Prospect property between August 3, 2006 and June 19, 2007, specifically wells CMR-USA-39-14, Dixon #1, Faust #1 TEC F-1, CMR/BR F-14, RB F-1 Red Bug #2, BR F-33, and Randall #1 F-4, and any offset wells that could be drilled to any of these specified wells.

Impairment

Under the full cost method, the Company is subject to a ceiling test. This ceiling test determines whether there is an impairment to the proved properties. The impairment amount represents the excess of capitalized costs over the present value, discounted at 10%, of the estimated future net cash flows from the proven oil and gas reserves plus the cost, or estimated fair market value. There was no impairment cost for the year ended October 31, 2009 or 2008, respectively.

Depletion

Under the full cost method, depletion is computed on the units of production method based on proved reserves, or upon reasonable estimates where proved reserves have not yet been established due to the recent commencement of production. Depletion expense recognized was \$186,354 and \$287,435 for the years ended October 31, 2009 and 2008, respectively.

3. OIL AND GAS INTERESTS (continued)

Capitalized Costs

	October 31, 2009	October 31, 2008
Proved properties	\$ 2,571,104	\$ 2,106,564
Unproved properties	270,459	64,000
Total Proved and Unproved properties	2,841,563	2,170,564
Accumulated depletion expense	(985,014)	(798,660)
Accumulated Impairment	(219,539)	(219,539)
Net capitalized cost	\$ 1,637,010	\$ 1,152,365

Results of Operations

Results of operations for oil and gas producing activities during the years ended are as follows:

	October 31, 2009	October 31, 2008
Revenues	\$ 398,274	\$ 1,497,908
Production costs	(113,769)	(266,691)
Depletion and accretion	(190,046)	(291,585)
Results of operations (excluding corporate overhead)	\$ 94,459	\$ 939,632

4. LOANS AND INTEREST PAYABLE TO RELATED PARTIES

The unsecured loans and accrued interest at 6%, previously outstanding at October 31, 2007 were paid in full on January 9, 2008.

	October 31, 2009	October 31, 2008
Loan repayable on December 31, 2007, bears interest at 6% per annum, and is unsecured	\$ -	\$ 19,070
Total loans	-	19,070
Plus: accrued interest	-	2,815
Total loans and interest payable	-	21,885
Less: amount paid	-	(20,714)
Less: exchange gain	-	(1,171)
	\$ -	\$ -

Interest expensed was \$ nil for the year ended October 31, 2009 and \$209 for the year ended October 31, 2008.

5. ASSET RETIREMENT OBLIGATIONS

The Company follows FASB ASC 410-20 "Accounting for Asset Retirement Obligations" which addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. This policy requires recognition of the present value of obligations associated with the retirement of tangible long-lived assets in the period in which it is incurred. As of October 31, 2009 and October 31, 2008, we recognized the future cost to plug and abandon the gas wells over the estimated useful lives of the wells in accordance with "Accounting for Asset Retirement Obligations". The liability for the fair value of an asset retirement obligation with a corresponding increase in the carrying value of the related long-lived asset is recorded at the time a well is completed and ready for production. The Company amortizes the amount added to the oil and gas properties and recognizes accretion expense in connection with the discounted liability over the remaining life of the respective well. The estimated liability is based on historical experience in plugging and abandoning wells, estimated useful lives based on engineering studies, external estimates as to the cost to plug and abandon wells in the future and federal and state regulatory requirements. The liability is a discounted liability using a credit-adjusted risk-free rate of 12%.

5. ASSET RETIREMENT OBLIGATIONS (continued)

Revisions to the liability could occur due to changes in plugging and abandonment costs, well useful lives or if federal or state regulators enact new guidance on the plugging and abandonment of wells.

The Company amortizes the amount added to oil and gas properties and recognizes accretion expense in connection with the discounted liability over the remaining useful lives of the respective wells.

The information below reflects the change in the asset retirement obligations during the years ended October 31, 2009 and year ended October 31, 2008:

	October 31, 2009	October 31, 2008
Balance, beginning of period	\$ 30,766	\$ 34,584
Liabilities assumed	9,206	3,376
Revisions	(6,653)	(11,344)
Accretion expense	3,692	4,150
Balance, end of period	<u>\$ 37,011</u>	<u>\$ 30,766</u>

The reclamation obligation relates to the Kodesh, Dye Estate, KC 80 and William wells at the Three Sands Property; the Palmetto Point Project well at the Frio-Wilcox Project; and ARD#1-36, Bagwell#1-20, Selman#1-21 and Selman#2-21 wells at Oklahoma Properties. The present value of the reclamation liability may be subject to change based on management's current estimates, changes in remediation technology or changes in applicable laws and regulations. Such changes will be recorded in the accounts of the Company as they occur.

6. COMMON STOCK

STOCK OPTIONS

Although the Company does not have a formal stock option plan, all options granted in the past have been approved by the Board of Directors.

On November 2, 2007, the Company granted a non-qualified stock option with respect to 200,000 shares to the President. The exercise price is \$0.24 per share. The Option shall expire and be canceled two years from the Grant Date and is one hundred percent (100%) vested as of the Grant Date. The Company recorded a total of \$26,077 for stock compensation expenses.

On October 30, 2009, the Company granted a non-qualified stock option with respect to 200,000 shares to the CFO. The exercise price is \$0.10 per share. The Option will fully vest in six months and expire in two years from the Grant Date. The Company recorded a total of \$136 for stock compensation expenses.

A summary of the changes in stock options for the year ended October 31, 2009 is presented below:

	Options Outstanding	
	Number of Shares	Weighted Average Exercise Price
Balance, October 31, 2007	-	\$ -
Grant on November 2, 2007	200,000	0.24
Exercised	-	-
Balance, October 31, 2008	200,000	\$ 0.24
Granted on October 30, 2009	200,000	0.10
Exercised	-	-
Balance, October 31, 2009	<u>400,000</u>	<u>\$ 0.17</u>

6. COMMON STOCK (continued)

The Company has the following options outstanding and exercisable.

October 31, 2009		Options outstanding and exercisable	
Range of exercise prices	Number of shares	Weighted average remaining contractual life	Weighted Average Exercise Price
\$0.24	200,000	0.01 years	0.24
\$0.10	200,000	1.99 years	0.10

7. RELATED PARTY TRANSACTIONS

During the years ended October 31, 2009 and 2008, the Company entered into the following transactions with related parties:

- The Company paid \$60,000 (2008 - \$57,000) in management fees and reimbursement of office space \$4,800 (2008 - \$4,800) to the President of the Company.
- The Company paid \$60,500 (2008 - \$48,128) to a related entity, for administration services, and \$96,500 (2008 - \$ 12,084) for consulting.
- The Company paid \$102,000 (2008 - \$42,500) in management fees to the director of the Company.
- Interest expense on loans payable to related parties totaled \$nil and \$209 for the year ended October 31, 2009 and 2008 respectively.

8. INCOME TAXES

Income tax expense (benefit) for the years ended October 31, 2009 and for the year ended October 31, 2008 consists of the following:

	October 31 2009	October 31 2008 (Restated)
Current Taxes Receivable	\$ (246,775)	\$ 351,374
Deferred Taxes	165,861	-
Less: valuation allowance	(165,861)	-
Net income tax provision (benefit)	<u>\$ (246,775)</u>	<u>\$ 351,374</u>

The effective income tax rate for years ended October 31, 2009 and the year ended October 31, 2008 differs from the U.S. Federal statutory income tax rate due to the following:

	October 31 2009	October 31 2008 (Restated)
Federal statutory income tax rate	(34.00%)	(34.0%)
State income taxes, net of federal benefit	(3.73%)	(3.91%)
Permanent differences in debt	0%	0%
Increase in valuation allowance	37.73%	37.91%
Net income tax provision (benefit)	<u>-</u>	<u>-</u>

8. INCOME TAXES (continued)

The components of the deferred tax assets and liabilities as of October 31, 2009 and as of October 31, 2008 are as follows:

	October 31 2009	October 31 2008
Deferred tax assets:		
Federal and state net operating loss carryovers	\$ 108,800	\$ -
Excess percentage depletion	57,061	29,733
Asset retirement liability	-	11,664
Deferred tax asset	<u>\$ 165,861</u>	<u>\$ 41,397</u>
Deferred tax liabilities:		
Intangible drilling costs and other exploration costs capitalized for financial reporting purposes	<u>\$ -</u>	<u>\$ -</u>
Net deferred tax asset/(liability)	165,861	41,397
Less: valuation allowance	<u>(165,861)</u>	<u>(41,397)</u>
Deferred tax liability	<u><u>\$ -</u></u>	<u><u>\$ -</u></u>

The Company has \$636,538 net operating loss carryover as of October 31, 2009 and Nil as of October 31, 2008 which will expire on October 31, 2029.

9. UNAUDITED OIL AND GAS RESERVE QUANTITIES

The following unaudited reserve estimates presented as of October 31, 2009 and 2008 were prepared by independent petroleum engineers. There are many uncertainties inherent in estimating proved reserve quantities and in projecting future production rates and the timing of development expenditures. In addition, reserve estimates of new discoveries that have little production history are more imprecise than those of properties with more production history. Accordingly, these estimates are expected to change as future information becomes available.

Proved oil and gas reserves are the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions; i.e., process and costs as of the date the estimate is made. Proved developed oil and gas reserves are those reserves expected to be recovered through existing wells with existing equipment and operating methods.

Unaudited net quantities of proved developed reserves of crude oil and natural gas (all located within United States) are as follows:

	Crude Oil (Bbls)	Natural Gas (MCF)
Changes in proved reserves		
Estimated quantity, October 31, 2007	115,913	145,395
Revisions of previous estimate	8,942	(16,327)
Discoveries	6,112	28,385
Reserves sold to third parties	(96,081)	(31,082)
Production	<u>(12,465)</u>	<u>(27,620)</u>
Estimated quantity, October 31, 2008	<u>22,421</u>	<u>98,751</u>
Revisions of previous estimate	9,933	(21,618)
Discoveries	30,550	14,890
Production	<u>(6,461)</u>	<u>(18,597)</u>
Estimated quantity, October 31, 2009	<u><u>56,443</u></u>	<u><u>73,426</u></u>

9. **UNAUDITED OIL AND GAS RESERVE QUANTITIES (continued)**

Proved Reserves at year end	Developed	Undeveloped	Total
Crude Oil (Bbls)			
October 31, 2009	25,773	30,670	56,443
October 31, 2008	8,781	13,640	22,421
Gas (MCF)			
October 31, 2009	62,626	10,800	73,426
October 31, 2008	98,751	-	98,751

The following information has been developed utilizing procedures prescribed by FASB ASC 932-235-55, *Disclosures About Oil and Gas Producing Activities*, and based on crude oil and natural gas reserves and production volumes estimated by the Company. It may be useful for certain comparison purposes, but should not be solely relied upon in evaluating the Company or its performance. Further, information contained in the following table should not be considered as representative or realistic assessments of future cash flows, nor should the Standardized

Measure of Discounted Future Net Cash Flows be viewed as representative of the current value of the Company.

Future cash inflows were computed by applying year-end prices of oil and gas to the estimated future production of proved oil and gas reserves. The future production and development costs represent the estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. Future income tax expenses were computed by applying statutory income tax rates to the difference between pre-tax net cash flows relating to our proved oil and gas reserves and the tax basis of proved oil and gas properties and available net operating loss carry-forwards. Discounting the future net cash inflows at 10% is a method to measure the impact of the time value of money.

	October 31, 2009	October 31, 2008
Future Cash inflows	\$ 4,684,335	\$ 12,069,056
Future production costs	(808,298)	(1,330,992)
Future development costs	(117,882)	(322,845)
Future income tax expense	(1,081,780)	(2,510,266)
Future cash flows	2,676,375	7,904,953
10% annual discount for estimated timing of cash flows	(135,787)	(3,921,816)
Standardized measure of discounted future net cash	<u>\$ 2,540,588</u>	<u>\$ 3,983,137</u>

UNAUDITED STANDARIZED MEASURE

The following presents the principal sources of the changes in the standardized measure of discounted future net cash flows.

Standardized measure of discounted cash flows:	October 31, 2009	October 31, 2008
Beginning of year	\$ 3,983,137	\$ 84,216
Sales and transfers of oil and gas produced, net production costs	(7,384,721)	(1,389,613)
Net changes in prices and production costs and other	522,694	1,267,335
Net changes due to discoveries	1,139,430	1,335,191
Changes in future development costs	204,963	322,845
Revisions of previous estimates	635,395	2,676,922

9. UNAUDITED OIL AND GAS RESERVE QUANTITIES (continued)

Other	-	27,405
Net change in income taxes	1,428,486	(747,762)
Accretion discount	2,011,204	406,598
Future cash flows	(1,422,549)	3,898,921
End of year	<u>\$ 2,540,588</u>	<u>\$ 3,983,137</u>

10. MAJOR CUSTOMERS

We collected \$171,418 (2008: \$953,846) or 43% of our revenues from one of our operators during the year ended October 31, 2009. As of October 31, 2009, \$58,602 was due from this operator.

11. SEGMENT REPORTING

The Company follows FASB ASC 280-10, *Disclosure about Segments of an Enterprise and Related Information*." Operating segments, as defined in the pronouncement, are components of an enterprise about which separate financial information is available and that are evaluated regularly by the Company in deciding how to allocate resources and in assessing performance.

The financial information is required to be reported on the basis that is used internally for evaluating segment performance and deciding how to allocate resources to segments.

As of October 31, 2009 and 2008, the Company had one operating segment, oil and gas exploration and development.

12. COMMITMENTS

The Company has the following oil and gas commitments resulting from the 2009-3 drilling program:

Oil and Gas drilling costs \$ 38,541

The Company has a month to month rental agreement with its office in New Mexico.

13. RESTATEMENT OF PRIOR YEARS

The Company failed to include Net Operating Loss carry forward in its deferred and current tax computation. As a result, prior year figures have been restated as shown in the tables below from what was previously issued in our Annual Report on Form 10-K filed with the SEC. The restatement was discovered during our year-end procedures.

Income Statement

	Restated	Reported	Difference
Total operating revenues	\$3,480,201	\$3,480,201	-
Operating Income/(loss)	\$2,481,734	\$2,481,734	-
Net Income/(loss)	\$2,130,151	\$1,563,808	\$566,343
Basic and diluted net income/(loss) per common share	0.09	0.06	0.03

13. **RESTATEMENT OF PRIOR YEARS (continued)**

Balance Sheet

	Restated	Reported	Difference
Total operating revenues	\$3,480,201	\$3,480,201	-
Operating Income/(loss)	\$2,481,734	\$2,481,734	-
Net Income/(loss)	\$2,130,151	\$1,563,808	\$566,343
Basic and diluted net income/(loss) per common share	0.09	0.06	0.03

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

On April 21, 2008, we dismissed Gordon, Hughes & Banks, LLP (“GHB”) as our independent registered public accounting firm. Also on April 21, 2008, we engaged Chisholm, Bierwolf & Nilson, LLC (“Chisholm”) to serve as our independent registered public accounting firm for fiscal year ending October 31, 2008. Our board of directors approved both actions.

The reports of GHB on our consolidated financial statements for the two most recent fiscal years ended October 31, 2007 and 2006, did not contain an adverse opinion or disclaimer of opinion and were not qualified or modified as to uncertainty, audit scope, or accounting principles, except that the audit reports for both years contained an explanatory paragraph regarding our ability to continue as a going concern.

In connection with the audit of our financial statements for fiscal year ended October 31, 2007, GHB advised us that based on several corrections to our financial statements and related disclosures proposed by GHB, there was a material weakness in our internal controls over financial reporting. Additionally, although we are not required to segregate the principal executive officer and principal financial officer functions and are not required to have an audit committee, GHB considered the fact that our sole officer at the time serves in both of these functions and that we do not have an audit committee as dispositive in providing its advice to us. As a result of this material weakness in our internal controls, our sole officer concluded further that the design and operation of our disclosure controls and procedures were not effective.

During the fiscal years ended October 31, 2007 and 2006 and through the subsequent interim period ending April 21, 2008, there were no disagreements with GHB on any matter of accounting principles or practices, financial statement disclosure or auditing scope or procedure, which disagreements, if not resolved to the satisfaction of GHB, would have caused GHB to make reference thereto in its report on our financial statements for such years. Further, except as described above, there were no reportable events as described in Item 304(a)(1)(v) of Regulation S-K occurring within our two most recent fiscal years and the subsequent interim period ending April 21, 2008.

We requested GHB to furnish us a letter addressed to the Commission stating whether it agreed with the above statements. A copy of that letter, dated April 25, 2008, was filed as Exhibit 16.1 to a current report on Form 8-K.

During our fiscal years ended October 31, 2007 and 2006 and through April 21, 2008, the period prior to the engagement of Chisholm, neither we nor anyone on our behalf consulted Chisholm regarding the application of accounting principles to a specific completed or contemplated transaction, or the type of audit opinion that might be rendered on the registrant’s financial statements. Further, Chisholm has not provided written or oral advice to us that was an important factor considered by us in reaching a decision as to any accounting, auditing or financial reporting issues.

ITEM 9A(T). CONTROLS AND PROCEDURES.

Evaluation of Disclosure Controls and Procedures

Disclosure controls and procedures, as defined in Rule 15d-15(e) under the Securities Exchange Act of 1934 (the “Exchange Act”), are our controls and other procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC’s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Act is accumulated and communicated to our officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

Rule 15d-15 under the Exchange Act, requires us to carry out an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures as of October 31, 2009, being the date of our most recently completed fiscal year end. This evaluation was conducted under the supervision and with the participation

of our officers, Leroy Halterman and Kulwant Sandher. Based on this evaluation, Messrs. Halterman and Sandher concluded that the design and operation of our disclosure controls and procedures are not effective since the following material weaknesses exist:

- We rely on external consultants for the preparation of our financial statements and reports. As a result, our officers may not be able to identify errors and irregularities in the financial statements and reports.
- We have an officer who is also a director. Our board of directors consists of only two members. Therefore, there is an inherent lack of segregation of duties and a limited independent governing board.
- We rely on an external consultant for administration functions, some of which do not have standard procedures in place for formal review by our officers.

Management's Annual Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rule 15d-15(f) under the Exchange Act. Our internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation and fair presentation of our financial statements for external purposes in accordance with generally accepted accounting principles. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Our officers have assessed the effectiveness of our internal controls over financial reporting as of October 31, 2009. In making this assessment, management used the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In conducting their evaluation, our officers considered advice from our Independent Registered Public Accounting Firm, Chisholm, Bierwolf & Nilson, LLC (“Chisholm”) that based on several minor corrections to our financial statements and related disclosures proposed by Chisholm, there may be material weaknesses in our internal controls over financial reporting. Specifically, the following deficiencies are noted:

- We do not have an Audit Committee. Although we are not legally required to have one, this means that we do not have entity control over our financial statements.
- While our external consultants provide sufficient documentation of our financial statements preparation and review procedures, our officers must rely on such documentation.
- We do not have proper segregation of duties for the preparation of our financial statements, resulting in journal entries being prepared and approved by the same person and lack of entity control over the preparation of financial statements.

As a result of these deficiencies in our internal controls, our officers concluded further that the design and operation of our disclosure controls and procedures may not be effective and that our internal control over financial reporting was not effective.

Our officers also considered various mitigating factors in making their determination. Our officers also noted that we are still evaluating and implementing changes in our internal controls in response to the requirements of Sarbanes Oxley §404. During fiscal 2010, we will continue to implement appropriate changes as they are identified, including changes to remediate material weaknesses in our internal controls.

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

Changes In Internal Controls Over Financial Reporting

In connection with the evaluation of our internal controls during our last fiscal quarter, we have made changes in the Company's internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. On September 25, 2009, we enacted new procedures requiring two signatures on all contracts and email or signatures to evidence approval of invoices. We also appointed an additional officer, Kulwant Sandher, to serve as the Chief Financial Officer of the Company on October 30, 2009.

ITEM 9B. OTHER INFORMATION.

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

Information about our executive officers and directors follows:

Name	Age	Position and Term of Office
Leroy Halterman	64	Director, President and Secretary
Kenneth A. Cabianca	69	Director
Kulwant Sandher	48	Chief Financial Officer

Our Bylaws provide for a board of directors ranging from 1 to 12 members, with the exact number to be specified by the board. All directors hold office until the next annual meeting of the stockholders following their election and until their successors have been elected and qualified. The board of directors appoints officers. Officers hold office until the next annual meeting of our board of directors following their appointment and until their successors have been appointed and qualified.

Set forth below is a brief description of the recent employment and business experience of our directors and executive officers:

Leroy Halterman was appointed as a director and as our sole officer at the time on August 9, 2005. Mr. Halterman has 40 years of geology experience. From 1999 to 2004, Mr. Halterman served as vice president of Tecumseh Professional Associates, a private environmental, facility management, government consultant and natural resource firm based in Albuquerque, New Mexico. During this period he directed the company's oil, gas and natural resource consulting and investments. Mr. Halterman served as principal in charge of maintenance and security for two U.S. Army Ammunition Plants. Additionally, he directed Tecumseh's efforts in over thirty mineral project appraisals and evaluations. Since 2004, Mr. Halterman has been working as a consultant in the fields of oil and gas, precious and base metals, and aggregated resources. Since 1993, Mr. Halterman has been president and a director of Consolidated North American Resources, a private natural resource investment firm located in Las Vegas, Nevada. Mr. Halterman is a graduate of the Missouri School of Mines with a BS degree in Geology. He is registered as a geologist in Wyoming. During the past five years, Mr. Halterman has not served as an officer or director of any company, other than as described in this paragraph.

Kenneth A. Cabianca was our sole officer and director from our inception in December 1998 until August 9, 2005. On August 9, 2005, Mr. Cabianca resigned as our president but he remains a director. Since 1983, Mr. Cabianca has been an independent businessman and a management consultant of various companies. Many of his activities have been conducted through his company, Wellington Financial Corporation. His experience includes raising venture capital, general management, and public relations. From August 1991 to September 1999, Mr. Cabianca was a director and president of Primo Resources International Inc., a mining company whose stock trades on the CDNX. While he served as president Primo Resources engaged in joint ventures projects with Mitsubishi Corp., Mitsubishi Materials Corp., and Golden Peaks Resources Ltd. He served as a director of Primo Resources International again from October 2001 to November 2002. Mr. Cabianca received a D.D.S. degree and practiced dentistry in Vancouver, British Columbia from 1965 to 1986. He also received a Bachelor of Science degree from Creighton University in 1965. During the past five years, Mr. Cabianca has not served as an officer or director of any company, other than as described in this paragraph.

Kulwant Sandher was appointed on October 30, 2009 our Chief Financial Officer. He has been the Chief Financial Officer and a director of Delta Oil & Gas, Inc., a publicly-traded company since January 2007. Mr. Sandher was appointed as President and Chief Financial Officer of Turner Valley Oil & Gas Inc., a publicly-traded company, on August 2004 and continues to serve in these positions. Mr. Sandher is a Chartered Accountant in both England and Canadian jurisdictions. From April 2006 to October 2008, Mr. Sandher acted as Chief Financial Officer and as a member of the board of directors of The Stallion Group. From May 2004 to March 2006, Mr. Sandher served as Chief Operating Officer and Chief Financial Officer of Marketrend Interactive Inc. He also acted

as Chief Financial Officer of Serebra Learning Corporation, a public company on the TSX Venture Exchange, from September 1999 to October 2002.

Conflicts of Interest

Our officers and directors are associated with other firms involved in a range of business activities. Consequently, there are potential inherent conflicts of interest in their acting as officers and/or directors of our company. Insofar as they are engaged in other business activities, we anticipate that they will not devote all of their time to our affairs.

Our officers and directors are now and may in the future become shareholders, officers or directors of other companies, which may be formed for the purpose of engaging in business activities similar to us. Accordingly, additional direct conflicts of interest may arise in the future with respect to such individuals acting on behalf of us or other entities. Moreover, additional conflicts of interest may arise with respect to opportunities which come to the attention of such individuals in the performance of their duties or otherwise. Currently, we do not have a right of first refusal pertaining to opportunities that come to their attention and may relate to our business operations.

Our officers and directors are, so long as they are our officers or directors, subject to the restriction that all opportunities contemplated by our plan of operation which come to their attention, either in the performance of their duties or in any other manner, will be considered opportunities of, and be made available to us and the companies that they are affiliated with on an equal basis. A breach of this requirement will be a breach of the fiduciary duties of the officer or director. If we or the companies with which the officers and directors are affiliated both desire to take advantage of an opportunity, then said officers and directors would abstain from negotiating and voting upon the opportunity. However, all directors may still individually take advantage of opportunities if we should decline to do so. Except as set forth above, we have not adopted any other conflict of interest policy with respect to such transactions.

We do not have any audit, compensation, and executive committees of our board of directors. We do not have an audit committee financial expert.

Section 16(a) Beneficial Ownership Reporting Compliance

We are not subject to Section 16(a) of the Securities Exchange Act of 1934.

Code of Ethics

We have not yet adopted a code of ethics that applies to our principal executive officers, principal financial officer, principal accounting officer or controller, or persons performing similar functions, due to our relatively low level of activity to date. At a later time, the board of directors may adopt such a code of ethics.

Changes to Director Nominating Procedures

The Company adopted Amended and Restated Bylaws on December 10, 2009 pursuant to which Series A Preferred Shareholders would be entitled to elect one director to the Company's board of directors. The Company has not issued any Series A Preferred Shares.

ITEM 11. EXECUTIVE COMPENSATION.

The following table sets forth information about the remuneration of our principal executive officer for services rendered for each of the last two fiscal years ended October 31, 2009. We do not have any executive officers with total compensation of \$100,000 or more. Certain columns as required by the regulations of the Securities and Exchange Commission have been omitted as no information was required to be disclosed under those columns.

SUMMARY COMPENSATION TABLE

Name and Principal Position	Year	Salary (\$)	Option Awards (\$)	Total (\$)
Leroy Halterman	2009	60,000	-0-	60,000
President and Secretary (1)	2008	57,000	26,077	83,077

In addition to the above, we reimbursed Mr. Halterman \$4,800 for each of the last two fiscal years for office space.

During the last two fiscal years ended October 31, 2009, there were no grants of stock options, stock appreciation rights, benefits under long-term incentive plans or other forms of compensation involving our officers, except for the stock option grant made to Mr. Halterman in November 2007 and to Mr. Sandher on October 30, 2009. We have no employment agreements with our executive officers. We do not pay compensation to our directors for attendance at meetings. We reimburse our directors for reasonable expenses incurred during the course of their performance.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END

Name	Number of Securities Underlying Unexercised Options (#) exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options	Option Exercise Price (\$)	Option Expiration Date
Leroy Halterman	200,000	-0-	-0-	0.24	11/2/09

On November 2, 2009, we granted Mr. Halterman options to purchase 300,000 shares of common stock at \$0.10 per share. The options will fully vest six months from the date of grant and expire November 9, 2011.

The following table sets forth compensation of our directors for the last completed fiscal year ended October 31, 2009. Mr. Halterman does not receive any additional compensation for serving as a director.

DIRECTOR COMPENSATION

Name	Fees Earned or Paid in Cash (\$)	Stock Awards (\$)	Option Awards (\$)	All Other Compensation (\$)	Total (\$)
Kenneth Cabianca	90,000	-0-	-0-	12,000	102,000

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

The following table provides certain information as to the officers, directors and more than 5% shareholders. As of January 20, 2010, we had 24,529,832 shares common stock outstanding.

Name and Address of Beneficial Owner (1)	Amount and Nature of Beneficial Ownership	Percent of Class (2)
Kenneth A. Cabianca (3) 4519 Woodgreen Drive West Vancouver, B.C. V7S 2T8 Canada	2,800,000 (4)	11.4%
Leroy Halterman 820 Piedra Vista Rd NE Albuquerque, NM 87123	50,000	0.2%
Kulwant Sandher 604-700 West Pender Street Vancouver, B.C. V6C 1G8 Canada	0	--
All officers and directors as a group (3 persons)	2,850,000	11.6%

- (1) To our knowledge, except as set forth in the footnotes to this table and subject to applicable community property laws, each person named in the table has sole voting and investment power with respect to the shares set forth opposite such person's name.
- (2) This table is based on 24,529,832 shares of Common Stock outstanding as of January 20, 2010.
- (3) Kenneth Cabianca may be deemed to be a promoter of our company.
- (4) 128,000 shares of Common Stock are held by Golden Capital in trust for Mr. Cabianca.

Equity Compensation Plan Information

As of October 31, 2009, our compensation plans (including individual compensation arrangements) under which our equity securities are authorized for issuance, are as follows

EQUITY COMPENSATION PLAN INFORMATION

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by security holders	N/A	N/A	N/A
Equity compensation plans not approved by security holders	400,000	0.17	N/A
Total	400,000	N/A	N/A

Changes in Control

There are no agreements known to management that may result in a change of control of our company.

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

For the fiscal years ended October 31, 2009 and 2008, we incurred \$60,500 and \$48,128, respectively, for administrative services performed by Downtown Consulting. Downtown Consulting is an entity owned and controlled by Sarah Cabianca, the daughter of Kenneth Cabianca, and one of our shareholders.

On January 26, 2005, Mr. Cabianca advanced CAD\$15,600 (approximately US\$12,441) to us. Interest accrues on this loan at 6% per annum and the loan was originally due June 30, 2005. The term of the note was extended to December 31, 2005 by allonge. The term of the note was further extended to December 31, 2007 by allonge.

On May 11, 2005, Mr. Cabianca advanced CAD\$1,500 (approximately US\$1,195) to us. Interest accrues on this loan at 6% per annum and the loan was originally due on December 31, 2005. The term of the note was extended to December 31, 2005 by allonge. The term of the note was further extended to December 31, 2007 by allonge.

On June 22, 2005, Mr. Cabianca advanced US\$500 to us. Interest accrues on this loan at 6% per annum and the loan was originally due on December 31, 2005. The term of the note was extended to December 31, 2005 by allonge. The term of the note was further extended to December 31, 2007 by allonge.

On July 25, 2005, Mr. Cabianca advanced US\$170 to us. Interest accrues on this loan at 6% per annum and the loan was originally due on December 31, 2005. The term of the note was extended to December 31, 2005 by allonge. The term of the note was further extended to December 31, 2007 by allonge.

On August 2, 2005, Mr. Cabianca advanced US\$300 to us. Interest accrues on this loan at 6% per annum and the loan was originally due on December 31, 2005. The term of the note was extended to December 31, 2005 by allonge. The term of the note was further extended to December 31, 2007 by allonge.

As of January 9, 2008, Kenneth Cabianca was paid in full for all the loan advances referenced above, to include all accrued interest and all the related notes and allonges have been cancelled as a result.

As of October 31, 2009 and 2008, loans and accrued interest payable to related parties were \$-0- and \$209, respectively.

During the fiscal years ended October 31, 2009 and 2008, we paid \$60,000 and \$57,000, respectively, in management fees and \$4,800 and \$4,800, respectively, as reimbursement for office space to our president, Lee Halterman.

During the fiscal years ended October 31, 2009 and 2008, we paid \$102,000 and \$42,500, respectively, in management fees to a director, Ken Cabianca.

As of the date of this report, other than the transactions described above, there are no, and have not been since inception, any material agreements or proposed transactions, whether direct or indirect, with any of the following:

- any of our directors or officers;
- any nominee for election as a director;
- any principal security holder identified in Item 12 above; or
- any relative or spouse, or relative of such spouse, of the above referenced persons.

Future Transactions

All future affiliated transactions will be made or entered into on terms that are no less favorable to us than those that can be obtained from any unaffiliated third party.

Director Independence

Our common stock trades on the OTC Bulletin Board. As such, we are not currently subject to corporate governance standards of listed companies, which require, among other things, that the majority of the board of directors be independent.

Since we are not currently subject to corporate governance standards relating to the independence of our directors, we choose to define an "independent" director in accordance with the NASDAQ Global Market's requirements for independent directors (NASDAQ Marketplace Rule 4200). The NASDAQ independence definition includes a series of objective tests, such as that the director is not an employee of the company and has not engaged in various types of business dealings with the company. We do not currently have an independent director under the above definition. We do not list that definition on our Internet website.

We presently do not have an audit committee, compensation committee, nominating committee, executive committee of our Board of Directors, stock plan committee or any other committees.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES.

Audit Fees

For the fiscal year ended October 31, 2009, Chisholm, Bierwolf & Nilson, LLC (“CBN”) is expected to bill us approximately \$25,000 for the audit of our annual financial statements. For the fiscal year ended October 31, 2008, CBN billed us \$22,106 for the audit of our annual financial statements.

Audit-Related Fees

There were no fees billed for services reasonably related to the performance of the audit or review of our financial statements outside of those fees disclosed above under “Audit Fees” for fiscal years 2009 and 2008.

Tax Fees

For the fiscal year ended October 31, 2009, CBN is expected to bill us \$6,000 for tax compliance services. For the fiscal year ended October 31, 2008, CBN billed us \$5,975 for tax compliance services.

All Other Fees

There were no other fees billed by our principal accountants other than those disclosed above for fiscal years 2009 and 2008.

Pre-Approval Policies and Procedures

Prior to engaging our accountants to perform a particular service, our directors obtain an estimate for the service to be performed. The directors in accordance with our procedures approved all of the services described above.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

Regulation S-K Number	Exhibit
3.1	Articles of Incorporation (1)
3.2	Certificate of Change Pursuant to NRS 78.209 (2)
3.3	Amendment to the Articles of Incorporation (3)
3.4	Amended and Restated Bylaws (4)
4.1	Certificate of Designation of Rights, Preferences, and Privileges for Series A Preferred Stock (4)
16.1	Letter from Gordon, Hughes & Banks, LLP dated April 25, 2008 (5)
31.1	Rule 15d-14(a) Certification of Principal Executive Officer
31.2	Rule 15d-14(a) Certification of Principal Financial Officer
32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 of Principal Executive Officer
32.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 of Principal Financial Officer

- (1) Incorporated by reference to the exhibits to the registrant's registration statement on Form SB-1, file number 333-102441.
- (2) Incorporated by reference to the exhibits to the registrant's current report on Form 8-K dated September 26, 2004, filed September 27, 2004.
- (3) Incorporated by reference to the exhibits to the registrant's current report on Form 8-K dated December 3, 2008, filed January 13, 2009.
- (4) Incorporated by reference to the exhibits to the registrant's current report on Form 8-K dated December 11, 2009, filed December 15, 2009.
- (5) Incorporated by reference to the exhibits to the registrant's current report on Form 8-K dated April 21, 2008, filed April 25, 2009.

SIGNATURES

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

BRINX RESOURCES LTD

Date: January 29, 2010

By: /s/ Leroy Halterman
Leroy Halterman, President

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.

Signature	Title	Date
<u>/s/ Leroy Halterman</u> Leroy Halterman	President, Secretary and Director (principal executive officer)	January 29, 2010
<u>/s/ Kulwant Sandher</u> Kulwant Sandher	Chief Financial Officer (principal financial and accounting officer)	January 29, 2010
<u>/s/ Kenneth A. Cabisanca</u> Kenneth A. Cabisanca	Director	January 29, 2010