CROSS BORDER RESOURCES, INC.
Form 10-K
April 01, 2013

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

FORM 10-K

(Mark One)

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

For the year ended December 31, 2012

OR

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

For the transition period from ______________to ______________

Commission File Number 000-52738

CROSS BORDER RESOURCES, INC.
(Exact Name of Registrant as Specified in Its Charter)

Nevada (State or Other Jurisdiction of Incorporation or Organization)	98-0555508 (I.R.S. Employer Identification No.)
2515 McKinney Avenue, Suite 900 Dallas, TX (Address of Principal Executive Offices)	75201 (Zip Code)
(Registrant's Telephone Number, Including Area Code)	(210) 226-6700
Securities registered pursuant to Section 12(b) of the Act:	None
Securities registered pursuant to Section 12(g) of the Act:	Common Stock, par value $.001 (Title of class)

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

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

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 requirement for the past 90 days. Yes x No o

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

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

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

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

As of June 30, 2012 (the last business day of the registrant's most recently completed second fiscal quarter), the aggregate market value of the registrant's common stock (based on a reported closing market price of $1.60 per share on the OTCBB) held by non-affiliates of the registrant was approximately $12,948,916. For purposes of this computation, all officers, directors and 10% beneficial owners of the registrant are deemed to be affiliates. Such determination should not be deemed to be an admission that such officers, directors or 10% beneficial owners are, in fact, affiliates of the registrant.

As of April 1, 2013, there were 16,301,946 shares of common stock, $.001 par value per share, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None.

CROSS BORDER RESOURCES, INC.
FORM 10-K

TABLE OF CONTENTS

Forward-Looking Statements

This Annual Report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Statements that are not historical facts, including statements about our beliefs and expectations, are forward-looking statements. Forward-looking statements include statements preceded by, followed by or that include the words "may," "could," "would," "should," believe," "expect," anticipate," "plan," "estimate," "target," "project," "intend," similar expressions and the negative of such words and expressions, although not all forward-looking statements contain such words or expressions.

Forward-looking statements are only predictions and are not guarantees of performance. These statements generally relate to our plans, objectives and expectations for future operations and are based on management's current beliefs and assumptions, which in turn are based on its experience and its perception of historical trends, current conditions and expected future developments as well as other factors it believes are appropriate under the circumstances. Although we believe that the plans, objectives and expectations reflected in or suggested by the forward-looking statements are reasonable, there can be no assurance that actual results will not differ materially from those expressed or implied in such forward-looking statements. Forward-looking statements also involve risks and uncertainties. Many of these risks and uncertainties are beyond our ability to control or predict and could cause results to differ materially from the results discussed in such forward-looking statements. Such risks and uncertainties include, but are not limited to, the following:

- our ability to raise additional capital to fund future capital expenditures;
- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fully develop and produce our oil and natural gas properties;
- declines or volatility in the prices we receive for our oil and natural gas;
- general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business;
- risks associated with drilling, including completion risks, cost overruns and the drilling of non-economic wells or dry holes;
- uncertainties associated with estimates of proved oil and natural gas reserves;
- the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs;
- risks and liabilities associated with acquired companies and properties;
- risks related to integration of acquired companies and properties;
- potential defects in title to our properties;
- cost and availability of drilling rigs, equipment, supplies, personnel and oilfield services;
- geological concentration of our reserves;

- environmental or other governmental regulations, including legislation of hydraulic fracture stimulation;
- our ability to secure firm transportation for oil and natural gas we produce and to sell the oil and natural gas at market prices;
- exploration and development risks;
- management's ability to execute our plans to meet our goals;
- our ability to retain key members of our management team;
- weather conditions;
- actions or inactions of third-party operators of our properties;

- costs and liabilities associated with environmental, health and safety laws;
- our ability to find and retain highly skilled personnel;
- operating hazards attendant to the oil and natural gas business;
- competition in the oil and natural gas industry; and
- the other factors discussed under Item 1A. "Risk Factors" in this report.

Forward-looking statements speak only as of the date hereof. All such forward-looking statements and any subsequent written and oral forward-looking statements attributable to us or any person acting on our behalf are expressly qualified in their entirety by the cautionary statements contained or referred to in this section and any other cautionary statements that may accompany such forward-looking statements. Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements.

Glossary of Oil and Natural Gas Terms

The following are abbreviations and definitions of terms commonly used in the oil and natural gas industry and this Annual Report on Form 10-K.

“Bbl” One stock tank barrel or 42 U.S. gallons liquid volume of oil or other liquid hydrocarbons.

“Boe” One barrel of oil equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil and 42 gallons of natural gas liquids to one Bbl of oil.

“Boe/d” Boe per day.

“Btu” A British thermal unit is a measurement of the heat generating capacity of natural gas. One Btu is the heat required to raise the temperature of a one-pound mass of pure liquid water one degree Fahrenheit at the temperature at which water has its greatest density (39 degrees Fahrenheit).

“completion” The process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas, or in the case of a dry well, the reporting of abandonment to the appropriate agency.

“condensate” A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

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

“development costs” Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and natural gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, natural gas lines, and power lines, to the extent necessary in developing the proved reserves;

- drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly;

- acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

- provide improved recovery systems.

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

“dry well” A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

"exploration costs" Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and natural gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells.

“exploratory well” A well drilled for the purpose of discovering new reserves in unproven areas.

“field” An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

“formation” A layer of rock which has distinct characteristics that differ from nearby rock.

“gross acres” The total acres in which a working interest is owned.

“Henry Hub” The pricing point for natural gas futures contracts traded on the NYMEX.

“horizontal well” A well that is drilled vertically to a certain depth and then drilled at a right angle within a specific interval.

“hydraulic fracturing” or “fracing” A process involving the injection of fluids, usually consisting mostly of water, but typically including small amounts of sand and other chemicals, in order to create fractures extending from the wellbore through the rock formation to enable oil or natural gas to move more easily through the rock pores to a production well.

“lease operating expenses” The expenses, usually recurring, which pay for operating the wells and equipment on a producing lease.

“MBbl” One thousand barrels of oil or other liquid hydrocarbons.

“MBoe” One thousand barrels of oil equivalent.

“Mcf” One thousand cubic feet of natural gas.

“Mcf/d” One thousand cubic feet of natural gas per day.

“MMBoe” One million barrels of oil equivalent.

“MMBtu” One million British thermal units.

“MMcf” One million cubic feet of natural gas.

“natural gas” Natural gas and natural gas liquids.

“net acres” The sum of the fractional working interests owned in gross acres.

“NYMEX” The New York Mercantile Exchange.

“oil” Oil and condensate.

“overriding royalty interest” An interest in an oil and/or natural gas property entitling the owner to a share of oil and natural gas production free of costs of production.

“PDP” Proved developed producing reserves.

6

“PDNP” Proved developed non-producing reserves.

“play” A term applied to a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential natural gas and oil reserves.

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

“producing well” A well found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

“production costs” Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and natural gas produced. Examples of production costs (sometimes called lifting costs) are:

- costs of labor to operate the wells and related equipment and facilities;
- repairs and maintenance;
- materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities;
- property taxes and insurance applicable to proved properties and wells and related equipment and facilities; and
- severance taxes.

“productive well” A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

“proved developed reserves” Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

“proved properties” Properties with proved reserves.

“proved reserves” Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons, or LKH, as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil, or HKO, elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based, and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

“proved undeveloped reserves” Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required.

“PUD” Proved undeveloped reserves.

“PV-10” When used with respect to oil and natural gas reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the SEC.

“reasonable certainty” If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery, or EUR, with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

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

“reserves” Estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible as of a given date by application of development prospects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to market, and all permits and financing required to implement the project.

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

“sand” A geological term for a formation beneath the surface of the Earth from which hydrocarbons are produced. Its make-up is sufficiently homogenous to differentiate it from other formations.

“shale” Fine-grained sedimentary rock composed mostly of consolidated clay or mud. Shale is the most frequently occurring sedimentary rock.

“spacing” The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

“standardized measure” The present value of estimated future cash inflows from proved oil and natural gas reserves, less future development, abandonment, production and income tax expenses, discounted at 10% per annum to reflect the timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized measure differs from PV-10 because standardized measure includes the effect of future income taxes.

“stratigraphic test well” A drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intention of being completed for hydrocarbon production.

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

“vertical well” An oil or natural gas wellbore that is drilled from the surface to the depth of interest without directional deviation.

“wellbore” The hole drilled by the bit that is equipped for oil or natural gas production on a completed well. Also called well or borehole.

“working interest” The right granted to the lessee of a property to explore for and to produce and own oil, natural gas, or other minerals. The working interest owners bear the exploitation, development, and operating costs on either a cash, penalty, or carried basis.

PART I

Item 1. Business

Our Company

We are an oil and gas exploration company. We currently own over 865,893 gross (approximately 293,843 net) mineral and lease acres in New Mexico and Texas. Approximately 25,000 of these net acres exist within the Permian Basin. A significant majority of our acreage consists of either owned mineral rights or leases held by production, allowing us to hold lease rental payments to under $5,000 annually. The majority of our acreage interests consists of non-operated working interests except for certain core San Andres properties which we operate.

Current development of our acreage is focused on our prospective Bone Spring acreage located in the heart of the 1st and 2nd Bone Spring play. This play encompasses approximately 4,390 square miles across both New Mexico and Texas. We currently own varying, non-operated working interests in both Eddy and Lea Counties, New Mexico, along with our working interest partners that include Cimarex, Apache, Oxy Permian, Occidental, Oxy USA and, Mewbourne; all having significant footprints within this play, and are adding to those footprints through lease and corporate acquisitions.

History

We were originally formed on October 25, 2005 under the name “Language Enterprises Corp.” We subsequently changed our name to Doral Energy Corp. On July 29, 2008, we acquired a working interest in 66 producing oil fields and approximately 186 wells (the “Eddy County Properties”) in and around Eddy County, New Mexico. As a result of our acquisition of the Eddy County Properties, we changed our business focus to the acquisition, exploration, operation and development of oil and gas projects, and we ceased being a “shell company.” On August 4, 2008, we filed our Form 8-K that included the information that would be required if we were filing a general form for registration of securities on Form 10 as a smaller reporting company.

Effective January 3, 2011, we completed the acquisition of Pure Energy Group, Inc. as contemplated pursuant to the Pure Merger Agreement among our company, Doral Sub, Pure L.P. and Pure Sub, a wholly owned subsidiary of Pure L.P. Pursuant to the provisions of the Pure Merger Agreement, all of Pure L.P.’s oil and gas assets and liabilities were transferred to Pure Sub. Pure Sub was then merged with and into Doral Sub, with Doral Sub continuing as the surviving corporation. Upon completion of the Pure Merger, the outstanding shares of Pure Sub were converted into an aggregate of 9,981,536 shares of our common stock. Since the Pure Merger, Pure L.P. has distributed all of its shares of our common stock to the partners of Pure L.P. so that Pure L.P. is no longer a shareholder of our company.

Effective January 4, 2011, following closing of the Pure Merger, Doral Sub was merged with and into our company, with our company continuing as the surviving corporation. Upon completing the merger of Doral Sub with and into our company, we changed our name to “Cross Border Resources, Inc.”

Our Strengths

Large Acreage Position Consisting of Mineral Ownership and Leasehold Held by Production. Our acreage consists of more than 290,000 net mineral acres within the Permian Basin region of New Mexico and Southwest New Mexico. The majority of our acreage is made up of mineral ownership which carries no drilling commitments or leasehold obligations. We own minerals in both the Permian Basin region and Southwest New Mexico. Cross Border’s producing leasehold acreage is located entirely within the active Permian Basin region and is currently held by existing production. The combination of perpetual mineral ownership and unexpired leasehold held by production uniquely positions us as a strong Permian Basin exploration and production company with continued growth potential.

Existing Infrastructure. All of our producing Permian properties are located within established oil and natural gas producing areas or existing fields. We seek to enhance existing production in these properties by using engineering and geological expertise. These areas also have a fully developed transportation infrastructure, which allows us to transport our oil and natural gas to market without long-term delay or significant investment.

Our Properties

Currently, substantially all of our producing oil and natural gas properties are concentrated in the Permian Basin. The Permian Basin covers an area approximately 250 miles wide and 300 miles long in West Texas and Southeast New Mexico. The Permian Basin is one of the most prolific onshore oil and natural gas producing regions in the United States. It is characterized by an extensive production history, mature infrastructure, long reserve life and hydrocarbon potential in multiple producing formations.

Planned Operations

We plan to spend between $8 million and $12 million during fiscal 2013 to drill and complete wells, re-enter and complete wells, or improve infrastructure. Our main area of focus is the Tom Tom/Tomahawk Prospect, where we will begin work on the field alongside the execution of our remediation plan, described below. For fiscal 2013, this included the re-entry of 14 gross wells (11.7 net), drilling of 6 gross wells (5.2 net), and the improvement of field infrastructure. We will also spend capital in several non-operated prospect areas. Currently, we are committed to participating in the drilling of 12 gross wells (1.1 net) in fiscal 2013. We expect to finance these activities with cashflow generated from operations and availability under our line of credit with Independent Bank.

Competition

The oil and natural gas industry is highly competitive and we compete with a substantial number of other companies that have greater resources than we do. The largest of these companies explore for, produce and market oil and natural gas, carry on refining operations and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in our drilling and development operations, locating and acquiring prospective oil and natural gas properties and reserves and attracting and retaining highly skilled personnel. There is also competition between producers of oil and natural gas and other industries producing alternative energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the United States government; however, it is not possible to predict the nature of any such legislation or regulation that may ultimately be adopted or its effects upon our future operations. Such laws and regulations may, however, substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation. The effect of these risks cannot be accurately predicted.

Insurance

We currently maintain oil and gas commercial general liability protection relating to all of our oil and gas operations (including environmental and pollution claims) with a total limit of coverage in the amount of $2,000,000 (with no deductible) and excess liability protection with a total limit of $3,000,000 (with a deductible of $10,000).

As is common in the oil and gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because premium costs are considered prohibitive. In addition, pollution and environmental risks generally are not fully insurable. A loss not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Employees

As of December 31, 2012, we had no employees. We engage the services of our Interim President and Chief Accounting Office on a consulting or contract basis. We engage additional part-time consultants on an as-needed basis. We also rely on the availability of internal staff of Red Mountain Resources, Inc. (“Red Mountain”), the majority holder of our common stock, to assist with our operations. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages.

Hydraulic Fracturing Policies and Procedures

We contract with third parties to conduct hydraulic fracturing as a means to maximize the productivity of our oil and natural gas wells in almost all of our wells. Hydraulic fracturing involves the injection of water, sand, gel and chemicals under pressure into formations to fracture the surrounding rock and stimulate production.

Although average drilling and completion costs for each area will vary, as will the cost of each well within a given area, on average approximately 50% of the drilling and completion costs for our wells are associated with hydraulic fracturing activities. These costs are treated in the same way that all other costs of drilling and completing our wells are treated and are built into and funded through our normal capital expenditures budget. A change to any federal and state laws and regulations governing hydraulic fracturing could impact these costs and adversely affect our business and financial results. See "Risk Factors — Federal and state legislative and regulatory initiatives as well as governmental reviews relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays as well as adversely affect our level of production."

The protection of groundwater quality is important to us. Our policy and practice is to ensure our service providers follow all applicable guidelines and regulations in the areas where we have hydraulic fracturing operations. In addition, we send at least one engineer or an experienced consultant on our behalf to the well site to personally supervise each hydraulic fracture treatment.

We believe that the hydraulic fracturing operations on our properties are conducted in compliance with all state and federal regulations and in accordance with industry standard practices for groundwater protection. These protective measures include setting surface casing at a depth sufficient to protect fresh water zones as determined by applicable state regulatory agencies, and cementing the casing to create a permanent isolating barrier between the casing pipe and surrounding geological formations. The casing plus the cement are intended to prevent contact between the fracturing fluid and any aquifers during the hydraulic fracturing or other well operations. For recompletions of existing wells, the production casing is pressure tested prior to perforating the new completion interval. Injection rates and pressures are monitored at the surface during our hydraulic fracturing operations. Pressure is monitored on both the injection string and the immediate annulus to the injection string.

The vast majority of hydraulic fracturing treatments are made up of water and sand or other kinds of man-made propping agents. Our service providers track and report chemical additives that are used in the fracturing operation as required by the applicable governmental agencies.

Hydraulic fracturing requires the use of a significant amount of water. All produced water, including fracture stimulation water, is disposed of in a way that does not impact surface waters. All produced water is disposed of in permitted and regulated disposal facilities.

Environmental Matters and Regulation

Our exploration, development and production operations are subject to various federal, state and local laws and regulations governing health and safety, the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may, among other things: require the acquisition of permits to conduct exploration, drilling and production operations; govern the amounts and types of substances that may be released into the environment in connection with oil and natural gas drilling and production; restrict the way we handle or dispose of our wastes or of naturally occurring radioactive materials generated by our operations; cause us to incur significant capital expenditures to install pollution control or safety related equipment operating at our facilities; limit or prohibit construction or drilling activities in sensitive areas such as wetlands, wilderness areas or areas inhabited by endangered or threatened species; impose specific health and safety criteria addressing worker protection;

require investigatory and remedial actions to mitigate pollution conditions caused by our operations or attributable to former operations; impose obligations to reclaim and abandon well sites and pits and impose substantial liabilities on us for pollution resulting from our operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of orders enjoining some or all of our operations in affected areas.

Additionally, the United States Congress and federal and state agencies frequently revise environmental, health and safety laws and regulations, and their interpretations thereof, and any changes that result in more stringent and costly operational requirements or waste handling, disposal, cleanup and remediation requirements for the oil and natural gas industry could have a significant impact on our operating costs. The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations or new interpretations of enforcement policies that result in more stringent and costly waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our financial condition and results of operations. We may be unable to pass on such increased compliance costs to our customers.

We have been notified by the Bureau of Land Management (“BLM”) that environmental deficiencies exist on our Tom Tom Tomahawk field in Chaves and Roosevelt counties in New Mexico. We have submitted a plan to remediate such activities to the BLM and the plan has been accepted. Before work can commence, we have to perform certain procedures such as sampling the soil. For the year ended December 31, 2012, we recorded a non-cash charge of $2,100,000 which is management’s best estimate of the costs to remediate the environmental deficiencies. This estimate could materially differ from actual expenditures. We cannot assure you that the passage of more stringent laws and regulations in the future will not have a further negative impact on our business, financial condition or results of operations.

The following is a summary of the more significant existing environmental, health and safety laws and regulations to which our business is subject and for which compliance may have a material adverse impact on our capital expenditures, financial condition or results of operations.

Comprehensive Environmental Response, Compensation and Liability Act

Comprehensive Environmental Response, Compensation and Liability Act (“CERCLA”), also known as the “Superfund” law, and comparable state statutes impose joint and several liability for costs of investigation and remediation and for natural resource damages without regard to fault or legality of the original conduct, on certain classes of persons with respect to the release into the environment of substances designated under CERCLA as hazardous substances. These classes of persons, or so–called potentially responsible parties (“PRPs”), include the current and past owners or operators of a site where the release occurred and anyone who transported or disposed or arranged for the transport or disposal of a hazardous substance found at the site. CERCLA also authorizes the Environmental Protection Agency (the “EPA”) and, in some instances, third parties to take actions in response to threats to public health or the environment and to seek to recover from the PRPs the costs of such action. Many states have adopted comparable or more stringent state statutes.

Although CERCLA generally exempts “petroleum” from the definition of hazardous substance, in the course of our operations, we will generate, transport and dispose or arrange for the disposal of wastes that may fall within CERCLA’s definition of hazardous substances. Comparable state statutes may not contain a similar exemption for petroleum. We may also be the owner or operator of sites on which hazardous substances have been released.

Solid and Hazardous Waste Handling

The Resource Conservation and Recovery Act (“RCRA”) and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of solid and hazardous waste. Although oil and natural gas waste generally is exempt from regulations as hazardous waste under RCRA, we will generate waste as a routine part of our operations that may be subject to RCRA and not all state and local laws contain a comparable exemption. Further, there is no guarantee that the EPA or individual states will not adopt more stringent requirements for the handling of non–hazardous waste or categorize some non–hazardous waste as hazardous in the future. Any such change could result in an increase in our costs to manage and dispose of waste, which could have a material adverse effect on our financial condition and results of operations.

It is also possible that our oil and natural gas operations may require us to manage naturally occurring radioactive materials, or NORM. NORM is present in varying concentrations in sub-surface formations, including hydrocarbon reservoirs, and may become concentrated in scale, film and sludge in equipment that comes in contract with crude oil and natural gas production and processing streams. Some states have enacted regulations governing the handling, treatment, storage and disposal of NORM.

Clean Water Act

The Clean Water Act and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of produced water and other oil and natural gas wastes, and fill materials into state waters and waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of certain permits issued by the EPA or an analogous state agency. Spill prevention, control and countermeasure (“SPCC”) requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by a permit issued by the United States Army Corps of Engineers. Federal and state regulatory agencies can impose administrative, civil and criminal penalties, as well as require remedial or mitigation measures, for non–compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. In the event of an unauthorized discharge of wastes, we may be liable for penalties and costs of remediation.

The Oil Pollution Act of 1990 (“OPA 90”) and its regulations impose requirements on “responsible parties” related to the prevention of oil spills and liability for damages resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A “responsible party” under the OPA 90 may include the owner or operator of an onshore facility. The OPA 90 subjects responsible parties to strict, joint and several financial liability for removal costs and other damages, including natural resource damages, caused by an oil spill that is covered by the statute. It also imposes other requirements on responsible parties, such as the preparation of an oil spill contingency plan. Failure to comply with the OPA 90 may subject a responsible party to civil or criminal enforcement action. We may conduct operations on acreage located near, or that affects, navigable waters subject to the OPA 90. We believe that compliance with applicable requirements under the OPA 90 will not have a material and adverse effect on us.

Safe Drinking Water Act

The Safe Drinking Water Act (the “SDWA”) regulates, among other things, underground injection operations. Hydraulic fracturing continues to be under intense regulatory scrutiny both at the federal level and at the state level. In past legislative sessions, the United States Congress considered two companion bills that if passed would have imposed on our hydraulic fracturing operations significantly more stringent requirements. In addition to subjecting the injection of hydraulic fracturing to the SDWA regulatory and permitting requirements, the proposed legislation would require the disclosure of the chemicals within the hydraulic fluids, which could make it easier for our competition to copy our operations and for third parties opposing hydraulic fracturing to initiate legal proceedings based on allegations that specific chemicals used in the process could adversely affect ground water. If this or similar legislation is enacted, we could incur substantial compliance costs and the requirements could negatively impact our ability to conduct fracturing activities on our assets.

Many states have considered or adopted legislation or regulations requiring the disclosure of the chemicals used in hydraulic fracturing. Texas has adopted such a program, which is administered by the Railroad Commission of Texas. The Wyoming Oil and Gas Conservation Commission also passed a rule requiring disclosure of hydraulic fracturing fluid. In addition, a number of states in which we plan to conduct, are currently conducting, or may in the future conduct, hydraulic fracturing operations regulatory reviews hydraulic fracturing and new regulations from such reviews could restrict or limit our access to shale formations or could delay our operations or make them more costly.

The BLM has proposed a comprehensive rule regulating hydraulic fracturing on federal and certain tribal lands. The rules impose disclosure requirements on the use of hydraulic fracturing chemicals. These proposed rules also require

BLM approval prior to hydraulic fracturing. BLM also would require operators to meet other substantive requirements relating to well integrity and recordkeeping.

The EPA recently issued draft guidance under the SDWA, providing direction about how it will address the use of diesel in hydraulic fracturing activities. The draft guidance provides a definition of diesel fuels and discusses how the EPA's Underground Injection Control rules will be applied to hydraulic fracturing. Further, in March 2010, the EPA announced that it would conduct a wide-ranging study on the effects of hydraulic fracturing on drinking water resources. Interim results of the study are expected in 2012, with final results expected in 2014. The agency also announced that one of its enforcement initiatives for 2011 to 2013 would be to focus on environmental compliance by the energy extraction sector. This additional regulatory scrutiny could make it difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

Air Emissions

Our operations are subject to federal, state and local regulations for the control of emissions from sources of air pollution under the Clean Air Act ("CAA") and analogous state and local programs. Federal and state laws require new and modified sources of air pollutants to obtain permits prior to commencing construction and also impose various monitoring and reporting requirements. Major sources of air pollutants are subject to more stringent, federally imposed requirements including additional permits. Federal and state laws designed to control hazardous or toxic air pollutants may require installation of additional controls. Administrative enforcement actions for failure to comply strictly with air pollution regulations or permits are generally resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could bring lawsuits for civil penalties or require us to forego construction, modification or operation of certain air emission sources.

On April 17, 2012, the EPA signed final rules under the CAA regarding emissions from oil and natural gas operations. The EPA rule subjects oil and natural gas operations to regulation under the New Source Performance Standards ("NSPS") and National Emissions Standards for Hazardous Air Pollutants ("NESHAPS"), programs under the CAA, and imposes new and amended requirements under both programs. The new rules, among other things, amend standards applicable to natural gas processing plants and would expand the NSPS to include all oil and natural gas operations, imposing requirements on those operations. The EPA also imposed NSPS standards for completions of hydraulically fractured natural gas wells, requiring the use of reduced emission completion techniques. The adopted rules allow in most circumstances, until January 1, 2015, facilities to combust natural gas that would escape during completion activities as an alternative to the reduced emission completion techniques. The NESHAPS proposal includes maximum achievable control technology standards for certain glycol dehydrators and storage vessels, and revises applicability provisions, alternative test protocols and the availability of the startup, shutdown and maintenance exemption. These new requirements may result in increased operating and compliance costs, increased regulatory burdens and delays in our operations. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

Climate Change Legislation

In response to certain scientific studies suggesting that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") are contributing to the warming of the Earth's atmosphere and other climatic changes, the United States Congress has considered legislation to reduce such emissions. To date, the United States Congress has failed to enact a comprehensive GHG program. Some states, either individually or on a regional level, have considered or enacted legal measures to reduce GHG emissions. Although most of the state-level initiatives have to date focused on large sources of GHG emissions, it is possible that smaller sources of emissions could become subject to GHG emission limitations. The cost of complying with these programs could be significant.

The EPA published finding that emissions of GHGs presented an endangerment to public health and the environment. These findings by the EPA allowed the agency to proceed through a rule-making process with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the CAA.

Consequently, the EPA adopted two sets of regulations that would require a reduction in emissions of GHGs from motor vehicles and could trigger permit review for GHG emissions from certain stationary sources. On June 3, 2010, the EPA published its final rule to address permitting of GHG emissions from stationary sources under the prevention of significant deterioration ("PSD") and Title V permitting programs. The final rule tailors the PSD and Title V permitting programs to apply to qualifying stationary sources of GHG emissions in a multi-step process, beginning January 2, 2011, with the largest sources first subject to permitting. In addition, the EPA has adopted a rule requiring the reporting of GHG emissions from specified large GHG emission sources in the United States. On November 8, 2010, the EPA finalized its regulations to expand its final rule on GHG emissions reporting to include onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities. Reporting of GHG emissions from such facilities will be required on an annual basis beginning in 2012 for emissions occurring in 2011. While we believe that we will be able to substantially comply with such reporting requirements without any material adverse effect to our financial condition, since such reporting requirements with respect to GHG emissions are new in the oil and natural gas industry, there can be no assurance that our reports will initially be in substantial compliance or that such requirements will not develop into more stringent and costly obligations that may have a significant impact on our operating costs. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas we produce. Any one of these climate change regulatory and legislative initiatives could have a material adverse effect on our business, financial condition and results of operations.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events; if any such effects were to occur, they could have a material adverse effect on our business and results of operations.

OSHA and Other Laws and Regulations on Employee Health and Safety

To the extent not preempted by other applicable laws, we are subject to the requirements of the Occupational Safety and Health Act ("OSHA") and comparable state statutes, where applicable. These laws and the implementing regulations strictly govern the protection of the health and safety of employees. The OSHA hazard communication standard, the EPA community right–to–know regulations under the Title III of CERCLA and similar state statutes, where applicable, require us to organize and maintain information about hazardous materials used or, as applicable, produced in our operations and that this information be provided to employees, state and local government authorities and, where applicable, citizens. OSHA may enforce workplace safety regulations through issuance of citations for violations of its standards, which include, but are not limited to, those regarding hazard communication, personal protective equipment, general environmental controls, and materials handling and storage. We believe that we are in substantial compliance with these requirements where applicable and with other applicable OSHA and comparable requirements.

National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands may be subject to the National Environmental Policy Act ("NEPA") which requires federal agencies, including the U.S. Department of the Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay or impose additional conditions upon the development of oil and natural gas projects.

Endangered Species Act

The Endangered Species Act, as amended (the "ESA"), and analogous state statutes restrict activities that may affect endangered and threatened species or their habitats. While some of our facilities may be located in areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Other Regulation of the Oil and Natural Gas Industry

The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities. In particular, oil and natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability.

Failure to comply with applicable laws and regulations can result in substantial penalties and possibly cessation of drilling and production operations. The regulatory burden on the industry increases the cost of doing business and affects profitability. We believe that we are in substantial compliance with existing requirements and such compliance will not have a material adverse effect on our financial condition, cash flows or results of operations. Nevertheless, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by the United States Congress, the states, the Federal Energy Regulatory Commission ("FERC") and the courts. We cannot predict when or whether any such proposals may become effective.

Drilling and Production

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

- the location of wells;
- the method of drilling and casing wells;
- the surface use and restoration of properties upon which wells are drilled; and
- the plugging and abandonment of wells.

State laws, including Texas, regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploitation while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil and natural gas within its jurisdiction.

In addition, 11 states have enacted surface damage statutes ("SDAs"). These laws are designed to compensate for damage caused by mineral development. Most SDAs contain entry notification and negotiation requirements to facilitate contact between operators and surface owners and users. Most also contain bonding requirements and specific expenses for exploration and producing activities. Costs and delays associated with SDAs could impair operational effectiveness and increase development costs.

We do not control the availability of transportation and processing facilities used in the marketing of our production. For example, we may have to shut-in a productive natural gas well because of a lack of available natural gas gathering or transportation facilities.

If we conduct operations on federal, state or Indian oil and natural gas leases, these operations must comply with numerous regulatory restrictions, including various non-discrimination statutes, royalty and related valuation requirements, and certain of these operations must be conducted pursuant to certain on-site security regulations and other appropriate permits issued by the Bureau of Land Management, the Bureau of Ocean Energy Management, Regulation and Enforcement or other appropriate federal or state agencies.

Transportation of Oil

Sales of oil are not currently regulated and are made at negotiated prices. Nevertheless, the United States Congress could reenact price controls in the future.

Our sales of oil are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate and access regulation. The FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil that allowed for an annual increase or decrease in the cost of transporting oil to the purchaser, effective July 1 of each year. The FERC reviews the indexing methodology every five years. In its latest order on the methodology, issued in December 2010, the FERC concluded that an index level of the Producer Price Index for Finished Goods plus 2.65 percent should be established for the five-year period commencing July 1, 2011.

Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When shipper nominations exceed full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

Transportation and Sales of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated by the FERC under the Natural Gas Act of 1938 (the "NGA"), the Natural Gas Policy Act of 1978 (the "NGPA"), and regulations issued under those statutes. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at market prices, the United State Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed all price controls affecting wellhead sales of natural gas effective January 1, 1993.

FERC regulates interstate natural gas transportation rates, and terms and conditions of service, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, the FERC issued a series of orders, beginning with Order No. 636, to implement its open access policies. As a result, the interstate pipelines' traditional role of providing the sale and transportation of natural gas as a single service has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although the FERC's orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

The price at which we sell natural gas is not currently subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical sales of these energy commodities, we are required to observe anti-market manipulation laws and related regulations enforced by the FERC and/or the Commodity Futures Trading Commission (the "CFTC"). See "—Other Federal Laws and Regulations Affecting Our Industry—Energy Policy Act of 2005." Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, sellers, royalty owners and taxing authorities. In addition, pursuant to Order No. 704, some of our operations may be required to annually report to the FERC on May 1 of each year for the previous calendar year. Currently, Order No. 704 requires certain natural gas market participants to report information regarding their reporting of transactions to price index publishers and their blanket sales certificate status, as well as certain information regarding their wholesale, physical natural gas transactions for the previous calendar year depending on the volume of natural gas transacted. See "—Other Federal Laws and Regulations Affecting Our Industry—FERC Market Transparency Rules."

Gathering services, which occur upstream of jurisdictional transmission services, are regulated by the states. In addition, intrastate natural gas transportation and facilities are also subject to regulation by state regulatory agencies, and certain transportation services provided by intrastate pipelines are also regulated by the FERC. The basis for regulation of intrastate natural gas transportation and gathering the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline and gathering pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

State Natural Gas Regulation

Various states, including Texas, regulate the drilling for, and the production, gathering and sale of, natural gas, including imposing severance taxes and requirements for obtaining drilling permits. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of natural gas resources. States may regulate rates of production and may establish maximum daily production allowables from natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that they will not do so in the future. The effect of these regulations may be to limit the amounts of natural gas that may be produced from our wells and to limit the number of wells or locations we can drill.

Other Federal Laws and Regulations Affecting Our Industry

Energy Policy Act of 2005

On August 8, 2005, President Bush signed into law the Energy Policy Act of 2005 (the "EPAct 2005"). The EPAct 2005 is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, the EPAct 2005 amends the NGA to add an anti-manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by the FERC, and furthermore provides the FERC with additional civil penalty authority. The EPAct 2005 provides the FERC with the power to assess civil penalties of up to $1.0 million per day for violations of the NGA and increases the FERC's civil penalty authority under the NGPA from $5,000 per violation per day to $1.0 million per violation per day. On January 19, 2006, the FERC issued Order No. 670, a rule that implements the anti-manipulation provision of the EPAct 2005 and makes it unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC: (1) to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act, practice, or course of business that operates as a fraud or deceit upon any person. The anti-manipulation rules and enhanced civil penalty authority reflect an expansion of the FERC's NGA enforcement authority. Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

FERC Market Transparency Rules

On April 19, 2007, the FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing, or Order No. 704. Under Order No. 704, wholesale buyers and sellers of more than 2.2 million MMBtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors, natural gas marketers and natural gas producers are required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order No. 704. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with the FERC's policy statement on price reporting. In 2011, a federal appellate court determined that FERC does not have legal authority to impose reporting requirements on wholly-intrastate pipelines.

Additional proposals and proceedings that might affect the natural gas industry are pending before the United State Congress, the FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our natural gas operations. We do not believe that we would be affected by any such action materially differently than similarly situated competitors.

Item 1A. Risk Factors

Risks Related to Our Business

We may not have sufficient capital to operate our business as presently contemplated.

The oil and natural gas industry is capital intensive. We make and expect to continue to make significant capital expenditures in our business for the exploration, development, production and acquisition of oil and natural gas reserves. Improvement in commodity prices may result in an increase in our actual capital expenditures.

We plan to spend between $8 million and $12 million during fiscal 2013 to drill and complete wells, re-enter and complete wells, or improve infrastructure. Our main area of focus is the Tom Tom/Tomahawk Prospect, where we will begin work on the field alongside the execution of our remediation plan. For fiscal 2013, this included the re-entry of 14 gross wells (11.7 net), drilling of 6 gross wells (5.2 net), and the improvement of field infrastructure. We will also spend capital in several non-operated prospect areas. Currently, we are committed to participating in the drilling of 12 gross wells (1.1 net) in fiscal 2013. We expect to finance these activities with cashflow generated from operations and availability under our line of credit with Independent Bank.

Our cash flows from operations and access to capital are subject to a number of variables, including:

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

Debt financing could lead to:

- a substantial portion of operating cash flow being dedicated to the payment of principal and interest;
- us being more vulnerable to competitive pressures and economic downturns; and
- restrictions on our operations, including our ability to pay dividends.

If sufficient capital resources are not available, we might be forced to cease operations entirely, curtail developmental and exploratory drilling and other activities or be forced to sell some assets on an untimely or unfavorable basis, which would have a material adverse effect on our business, financial condition and results of operations.

Our outstanding debt contains covenants restricting certain actions we may take.

Our credit agreement with Independent Bank contains various restricting certain actions we may take, including, but not limited to, incurring additional indebtedness, entering into any merger, selling any of our assets, making certain investments and paying dividends. The credit agreement also contains various financial covenants requiring us to maintain a certain ratio of debt compared to EBITDAX (as defined in the credit agreement). These restrictions and covenants may adversely effect our operations.

We may have difficulty managing growth in our business, which could adversely affect our financial condition and results of operations.

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

A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price we receive for our oil and natural gas will heavily influence our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions impacting the global supply and demand for oil and natural gas;
- the price and quantity of imports of foreign oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC, and other state-controlled oil companies relating to oil and natural gas price and production control;
- political conditions in or affecting other oil-producing and natural gas-producing countries, including the current conflicts in the Middle East and conditions in South America and Russia;
- the level of global oil and natural gas inventories;
- localized supply and demand fundamentals;
- the availability of refining capacity;

- price and availability of transportation and pipeline systems with adequate capacity;
- weather conditions and natural disasters;
- governmental regulations;

- speculation as to the future price of oil and the speculative trading of oil and natural gas futures contracts;
- price and availability of competitors' supplies of oil and natural gas;
- energy conservation and environmental measures;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels and energy sources; and
- domestic and international drilling activity.

Declines in oil and natural gas prices may materially adversely affect our financial condition, liquidity, and ability to finance planned capital expenditures and results of operations and may reduce the amount of oil and natural gas that we can produce economically. This could have a material adverse effect on our liquidity and financial condition.

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

We may acquire additional interests in oil and natural gas properties. Any future acquisitions will require an assessment of recoverable reserves, title, future oil and natural gas prices, operating costs, potential environmental hazards and liabilities, potential tax and Employee Retirement Income Security Act liabilities, and other liabilities and other similar factors. Generally, it is not feasible for us to review in detail every individual property involved in an acquisition, and our review efforts are normally focused on the higher-valued properties. Even a detailed review of properties and records may not reveal existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. We do not inspect every well that we acquire. Potential problems, such as deficiencies in the mechanical integrity of equipment or environmental conditions that may require significant remedial expenditures, are not necessarily observable even when we inspect a well. Any unidentified problems could result in material liabilities and costs that negatively impact our financial condition and results of operations.

Even if we are able to identify problems with an acquisition, the seller may be unwilling or unable to provide effective contractual protection or indemnity against all or part of these problems. Even if a seller agrees to provide indemnity, the indemnity may not be fully enforceable and may be limited by floors and caps on such indemnity. In addition, we may acquire oil and natural gas properties that contain commercially productive reserves which are less than predicted. Any of these factors could have a material adverse effect on our results of operations and reserve growth.

Our failure to successfully identify, complete and integrate future acquisitions of properties or businesses could reduce our earnings and slow our growth.

There is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our ability to complete acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Further, these acquisitions may be in geographic regions in which we do not currently operate, which could result in unforeseen operating difficulties and difficulties in coordinating geographically dispersed operations, personnel and facilities. In addition, if we enter into new geographic markets, we may be subject to additional and unfamiliar legal and regulatory requirements. Compliance with regulatory requirements may impose substantial additional obligations on us and our management, cause us to expend additional time and resources in compliance activities and increase our exposure to penalties or fines for non-compliance with such additional legal requirements. Completed acquisitions could require us to invest further in operational, financial and management information systems and to attract, retain, motivate and effectively manage additional employees. The inability to effectively manage the integration of acquisitions could reduce our focus on subsequent acquisitions and current operations, which, in turn, could negatively impact our earnings and growth. Our financial position and results of operations may fluctuate significantly from period to period, based on whether or not significant acquisitions are completed in particular periods.

We cannot control the development of the properties we do not operate, which may adversely affect our production, revenues and results of operations.

We do not operate the majority of the properties in which we have an interest. As a result, we have limited ability to exercise influence over, and control the risks associated with, the operation of these properties. The success and timing of our drilling and development activities on those properties depend upon a number of factors outside of our control, including:

- the timing and amount of capital expenditures;
- the operators' expertise and financial resources;
- the approval of other participants in drilling wells; and
- the selection of suitable technology.

As a result of any of the above or an operator's failure to act in ways that are in our best interest, our allocated production revenues and results of operations could be adversely affected.

Drilling for and producing oil and natural gas are speculative activities and involve numerous risks and substantial and uncertain costs that could adversely affect us.

Our future financial condition and results of operations will depend on the success of our acquisition, exploitation, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially productive oil or natural gas reserves. Our decisions to acquire, explore, develop or otherwise exploit drilling locations or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. In addition, our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- shortages of or delays in obtaining equipment and qualified personnel;
- facility or equipment malfunctions;
- unexpected operational events;
- pressure or irregularities in geological formations;
- adverse weather conditions, such as flooding;
- reductions in oil and natural gas prices;
- delays imposed by or resulting from compliance with regulatory requirements;
- proximity to and capacity of transportation facilities;
- title problems;

- limitations in the market for oil and natural gas; and
- costs and availability of drilling rigs, equipment, supplies, personnel and oilfield services.

Even if drilled, our completed wells may not produce reserves of oil or natural gas that are commercially productive or that meet our earlier estimates of economically recoverable reserves. A productive well may become uneconomic if water or other deleterious substances are encountered, which impair or prevent the production of oil and/or natural gas from the well. Our overall drilling success rate or our drilling success rate for activity within a particular project area may decline. Unsuccessful drilling activities could result in a significant decline in our production and revenues and materially harm our operations and financial condition by reducing our available cash and resources.

Reserve estimates depend on many assumptions that may turn out to be inaccurate.

Any material inaccuracies in our reserve estimates or underlying assumptions could materially affect the quantities and present values of our reserves. This Annual Report on Form 10-K contains estimates of our proved oil and natural gas reserves and PV-10 and standardized measure of our proved oil and natural gas reserves. The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities of reserves and amount of PV-10 and standardized measure that we may report. The process of preparing these estimates requires the projection of production rates and timing of development expenditures and analysis of available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also requires economic assumptions relating to matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities of reserves and amount of PV-10 and standardized measure that we may report. In addition, we may adjust estimates of proved reserves and amount of PV-10 and standardized measure to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control. Moreover, there can be no assurance that our reserves will ultimately be produced or that our proved undeveloped reserves will be developed within the periods anticipated. Any significant variance in the assumptions could materially affect the estimated quantity our reserves and amount of PV-10 and standardized measure.

Investors should not assume that the PV-10 of our proved reserves is the current market value of our estimated oil and natural gas reserves. PV-10 is based on prices and costs in effect on the date of the estimate. Actual future prices, costs, and the volume of produced reserves may differ materially from those used in the PV-10 estimate.

Approximately 33.9% of our total estimated proved reserves as of December 31, 2012 were classified as proved undeveloped and may not be ultimately developed or produced.

As of December 31, 2012, approximately 33.9% of our total estimated proved reserves were undeveloped. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The future drilling of proved undeveloped reserves is highly dependent upon our ability to fund our capital expenditures, which we estimate will be approximately $8.0 million to $12.0 million for 2013. We cannot be sure that these estimated costs are accurate, and we may be unable to obtain sufficient capital. Further, our drilling efforts may be delayed or unsuccessful, and actual reserves may prove to be less than current reserve estimates, which could have a material adverse effect on our financial condition, future cash flows and results of operations.

If we are unable to find purchasers of our natural gas, it could harm our profitability.

There generally are only a limited number of natural gas transmission companies with existing pipelines in the vicinity of a natural gas well or wells. In the event that producing natural gas properties are not subject to purchase contracts or that any such contracts terminate and other parties do not purchase our natural gas production, there is no assurance that we will be able to enter into purchase contracts with any transmission companies or other purchasers of natural gas and there can be no assurance regarding the price which such purchasers would be willing to pay for such natural gas. There presently exists an oversupply of natural gas in the marketplace, the extent and duration of which is not known. Such oversupply may result in reductions of purchases by principal natural gas pipeline purchasers.

If oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and natural gas properties.

We will review our proved oil and natural gas properties for impairment whenever events or changes in circumstances indicate that a decline in the recoverability of their carrying value may have occurred. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties, which may result in a decrease in the amount of future permitted indebtedness available. A write-down constitutes a non-cash charge to earnings. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

Unless we replace oil and natural gas reserves, our production and cash flows will decline.

Our future success will depend on our ability to find, develop or acquire additional reserves that are commercially productive. If we are unable to replace reserves through drilling or acquisitions, our level of production and cash flows will be adversely affected. In general, production from oil and natural gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our total proved reserves decline as reserves are produced unless we conduct other successful exploration and development activities or acquire properties containing proved reserves, or both. Our ability to make the necessary capital investment to maintain or expand our asset base of oil and natural gas reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. We may not be successful in exploring for, developing or acquiring additional reserves. We also may not be successful in raising funds to acquire, explore or develop additional reserves.

Prospects that we decide to drill may not yield oil or natural gas in commercially viable quantities.

Prospects that we decide to drill that do not yield oil or natural gas in commercially productive quantities will adversely affect our financial condition and results of operations. Our prospects are in various stages of evaluation, and may range from a prospect which is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation and other technical analysis. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be commercially productive. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects.

Market conditions or transportation impediments may hinder access to oil and natural gas markets or delay production.

Market conditions, the unavailability of satisfactory oil and natural gas transportation or the remote location of our drilling operations may restrict our access to oil and natural gas markets or delay production. The availability of a ready market for oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas, the proximity of reserves to pipelines or trucking and terminal facilities and the availability of trucks and other transportation equipment. We may be required to shut-in wells or delay initial production for lack of a viable market or because of inadequacy or unavailability of pipeline or gathering system capacity. When that occurs, we will be unable to realize revenue from those wells until the production can be tied to a gathering system. This can result in considerable delays from the initial discovery of a reservoir to the actual production of the oil and natural gas and realization of revenues.

Delays in obtaining permits by us for our operations could impact our business.

We are required to obtain permits from one or more governmental agencies in order to perform drilling and completion activities, including hydraulic fracturing. Such permits are typically required by state agencies, but can also be required by federal and local governmental agencies. As with all governmental permitting processes, there is a degree of uncertainty as to whether a permit will be granted, the time it will take for a permit to be issued, and the conditions which may be imposed in connection with the granting of the permit. Hydraulic fracturing activities has been particularly scrutinized. New York, for example, recently issued a moratorium currently in effect on the issuance of permits for inland drilling and completion activities. Subject to an Executive Order issued by Governor Paterson on December 13, 2010, the New York Department of Environmental Conservation will not issue permits for drilling and completion activities until it completes a final environmental impact study following public comment. Texas is not currently considering such a measure. In addition, on May 17, 2012, the Governor of Vermont signed a bill banning hydraulic fracturing in the state of Vermont. To date, Vermont is the first and only state to ban hydraulic fracturing. If we are unable to obtain the necessary permits for our operations, it could have a material adverse effect on our results of operations and profitability.

Our operations are subject to hazards inherent in the oil and natural gas industry.

We implement hydraulic fracturing in our operations, a process involving the injection of fluids—usually consisting mostly of water but typically including small amounts of several chemical additives—as well as sand in order to create fractures extending from the wellbore through the rock formation to enable oil or natural gas to move more easily through the rock pores to a production well. Risks inherent to our industry include the potential for significant losses associated with damage to the environment. Equipment design or operational failures, or vehicle operator error can result in explosions and discharges of toxic gases, chemicals and hazardous substances, and, in rare cases, uncontrollable flows of natural gas or well fluids into environmental media, as well as personal injury, loss of life, long-term suspension or cessation of operations and interruption of our business and/or the business or livelihood of third parties, damage to geologic formations, environmental media and natural resources, equipment and/or facilities and property. In addition, we use and generate hazardous substances and wastes in our operations and may become subject to claims relating to the release of such substances into the environment. In addition, some of our current properties are, or have been, used for industrial purposes, which could contain currently unknown contamination that could expose us to governmental requirements or claims relating to environmental remediation, personal injury and/or property damage. These conditions could expose us to liability for personal injury, wrongful death, property damage, loss of oil and natural gas production, pollution and other environmental damages and, in an extreme case, could materially impair our profitability, competitive position or viability. Depending on the frequency and severity of such liabilities or losses, it is possible that our operating costs, insurability and relationships with employees and regulators could be materially impaired.

Our business and operations may be adversely affected by regulations affecting the oil and natural gas industry.

Our business and operations are subject to and impacted by a wide array of federal, state, and local laws and regulations on the exploration for and development, production, and marketing of oil and natural gas, the operation of oil and natural gas wells, taxation, and environmental and safety matters. Many laws and regulations require drilling permits and govern the spacing of wells, rates of production, prevention of waste and other matters. The technical requirements of these laws and regulations are becoming increasingly stringent, complex and costly to implement. The high cost of compliance with applicable regulations may cause us to limit or discontinue our operation and development activities.

Changes in regulations and laws relating to the oil and natural gas industry could result in our operations being disrupted or curtailed by government authorities. For example, oil and natural gas exploration and production may become less cost effective and decline as a result of increasingly stringent environmental requirements (including land use policies responsive to environmental concerns and delays or difficulties in obtaining environmental permits). A decline in exploration and production, in turn could have a material adverse effect on our business, financial condition, results of operations and cash flows.

The unavailability or high cost of drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute exploration plans on a timely basis and within budget.

We are highly dependent upon third-party services. The cost of oilfield services typically fluctuates based on demand for those services. There is no assurance that we will be able to contract for such services on a timely basis or that the cost of such services will remain at a satisfactory or affordable level. Shortages or the high cost of drilling rigs, equipment, supplies or personnel could delay or adversely affect our exploration operations, which could have a material adverse effect on our business, financial condition or results of operations.

Production of oil and natural gas could be materially and adversely affected by natural disasters or severe or unseasonable weather.

Production of oil and natural gas could be materially and adversely affected by natural disasters or severe weather. Repercussions of natural disasters or severe weather conditions may include:

- evacuation of personnel and curtailment of operations;
- damage to drilling rigs or other facilities, resulting in suspension of operations;
- inability to deliver materials to worksites; and
- damage to pipelines and other transportation facilities.

In addition, our hydraulic fracturing operations require significant quantities of water. Texas recently has experienced drought conditions. Any diminished access to water for use in hydraulic fracturing, whether due to usage restrictions or drought or other weather conditions, could curtail our operations or otherwise result in delays in operations or increased costs.

Operating hazards, natural disasters or other interruptions of our operations could result in potential liabilities, which may not be fully covered by our insurance.

The oil and natural gas business generally, and our operations specifically, are subject to certain operating hazards such as:

- accidents resulting in serious bodily injury and the loss of life or property;
- liabilities from accidents or damage by our equipment;
- well blowouts;
- cratering (catastrophic failure);
- explosions;
- uncontrollable flows of oil, natural gas or well fluids;
- abnormally pressurized formations;
- fires;

- reservoir damage;
- oil spills;
- pollution and other damage to the environment; and
- releases of toxic gas.

In addition, our operations are susceptible to damage from natural disasters such as flooding or tornados, which involve increased risks of personal injury, property damage and marketing interruptions. The occurrence of one of these operating hazards may result in injury, loss of life, suspension of operations, environmental damage and remediation and/or governmental investigations and penalties. The payment of any of these liabilities could reduce, or even eliminate, the funds available for exploration and development, or could result in a loss of our properties. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could materially adversely affect our financial condition, results of operations and cash flows.

Our insurance might be inadequate to cover our liabilities. Insurance costs are expected to continue to increase over the next few years, and we may decrease coverage and retain more risk to mitigate future cost increases. If we incur substantial liability, and the damages are not covered by insurance or are in excess of policy limits, then our business, results of operations and financial condition may be materially adversely affected.

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

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

Competition in the oil and natural gas industry is intense, and many of our competitors have resources that are greater than ours.

We operate in a highly competitive environment for developing and acquiring properties, marketing oil and natural gas and securing equipment and trained personnel. As a relatively small oil and natural gas company, many of our competitors, major and large independent oil and natural gas companies, possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to develop and acquire more prospects and productive properties than our financial or personnel resources permit. Our ability to acquire additional prospects and discover reserves in the future will depend on our ability to evaluate and select suitable properties and execute our exploration and development activities in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Larger competitors may be better able to withstand sustained periods of unsuccessful drilling and absorb the burden of changes in laws and regulations more easily than we can, which would adversely affect our competitive position. We may not be able to compete successfully in the future in developing reserves, acquiring prospective oil and natural gas properties and reserves, attracting and retaining highly skilled personnel and raising additional capital.

We may be unable to diversify our operations to avoid any downturn in the oil and natural gas industry.

Because of our limited financial resources, it is unlikely that we will be able to diversify our operations the way companies with greater financial resources are able to do. Our inability to diversify our activities will subject us to economic fluctuations within the oil and natural gas industry and therefore increase the risks associated with our operations as limited to one industry.

Certain federal income tax deductions currently available with respect to oil and natural gas exploration and development may be eliminated as a result of future legislation.

President Obama’s proposed Fiscal Year 2013 Budget includes proposed legislation that would, if enacted into law, make significant changes to United States tax laws, including the elimination or postponement of certain key United States federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of the current deduction for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in United States federal income tax laws could eliminate certain tax deductions that are currently available with respect to oil and natural gas exploration and development.

Federal and state legislative and regulatory initiatives as well as governmental reviews relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays as well as adversely affect our level of production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. However, the EPA has asserted federal regulatory authority over certain hydraulic fracturing practices. Also, legislation has been introduced, but not enacted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Certain states, including Texas, and municipalities have adopted, or are considering adopting, regulations that have imposed, or that could impose, more stringent permitting, disclosure, disposal and well construction requirements on hydraulic fracturing operations. For example, in December 2011, the Railroad Commission of Texas finalized regulations requiring public disclosure of all the chemicals in fluids used in the hydraulic fracturing process. Local ordinances or other regulations may regulate or prohibit the performance of well drilling in general and hydraulic fracturing in particular. If new laws or regulations that significantly restrict or regulate hydraulic fracturing are adopted, such legal requirements could cause project delays and make it more difficult or costly for us to perform fracturing to stimulate production from a formation. These delays or additional costs could adversely affect the determination of whether a well is commercially viable. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce in commercial quantities.

In addition, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. Moreover, the EPA announced on October 20, 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards by 2014 that such wastewater must meet before being transported to a treatment plant. On August 16, 2012, the EPA published final rules under the CAA that, among other things, imposed NSPS standards for completions of hydraulically fractured natural gas wells, requiring the use of reduced emission completion techniques.

In addition, the U.S. Department of Energy is conducting an investigation into hydraulic fracturing practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods. Also, the U.S. Department of the Interior is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands. Additionally, certain members of Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources; the Securities and Exchange Commission (“SEC”) to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing; and the U.S. Energy Information Administration to provide a better understanding of that agency’s estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms.

Our business exposes us to liability and extensive regulation on environmental matters, which could result in substantial expenditures.

Our operations are subject to numerous U.S. federal, state and local laws and regulations relating to the protection of the environment, including those governing the discharge of materials into the water and air, the generation, management and disposal of hazardous substances and wastes and the clean-up of contaminated sites. We could incur material costs, including clean-up costs, fines and civil and criminal sanctions, injunctive relief and third-party claims for property damage and personal injury as a result of violations of, or liabilities under, environmental laws and regulations. Such laws and regulations not only expose us to liability for our own activities, but may also expose us to liability for the conduct of others or for actions by us that were in compliance with all applicable laws at the time those actions were taken. In addition, we could incur substantial expenditures complying with environmental laws and regulations, including future environmental laws and regulations which may be more stringent, for example, the regulation of GHG emissions under the federal CAA, or state or regional regulatory programs. Regulation of GHG emissions by the EPA, or various states in the United States in areas in which we conduct business, could have an adverse effect on our operations and demand for our oil and natural gas production. Moreover, the EPA has shown a general increased scrutiny on the oil and gas industry through its GHG, CAA and SDWA regulations.

On August 16, 2012, the EPA published final rules under the CAA regarding emissions from oil and natural gas operations. The EPA rule subjects oil and natural gas operations to regulation under the NSPS and NESHAPS, programs under the CAA, and imposes new and amended requirements under both programs. The new rules, among other things, amend standards applicable to natural gas processing plants and would expand the NSPS to include all oil and natural gas operations, imposing requirements on those operations. The EPA also imposed NSPS standards for completions of hydraulically fractured natural gas wells, requiring the use of reduced emission completion techniques. The adopted rules allow facilities, in most circumstances until January 1, 2015, to combust natural gas that would escape during completion activities as an alternative to the reduced emission completion techniques. The NESHAPS rules includes MACT standards for certain glycol dehydrators and storage vessels, and revises applicability provisions, alternative test protocols and the availability of the startup, shutdown and maintenance exemption. These new requirements may result in increased operating and compliance costs, increased regulatory burdens and delays in our operations.

Additionally, we have been notified by the BLM that environmental deficiencies exist on our Tom Tom Tomahawk field in Chaves and Roosevelt counties in New Mexico. We have submitted a plan to remediate such activities to the BLM and the plan has been accepted. Before work can commence, we have to perform certain procedures such as sampling the soil. For the year ended December 31, 2012, we recorded a non-cash charge of $2,100,000 which is management's best estimate of the costs to remediate the environmental deficiencies. This estimate could materially differ from actual expenditures. If this occurs on any of our other properties, it could have a material adverse effect on our financial condition and results of operations.

The EPA's implementation of climate change regulations could result in increased operating costs and reduced demand for our oil and natural gas production.

Although federal legislation regarding the control of emissions of GHGs, for the present, appears unlikely, the EPA has been implementing regulatory measures under existing CAA authority and some of those regulations may affect our operations. GHGs are certain gases, including carbon dioxide, a product of the combustion of natural gas, and methane, a primary component of natural gas, that may be contributing to the warming of the Earth's atmosphere, resulting in climatic changes. These GHG regulations could require us to incur increased operating costs and could have an adverse effect on demand for our oil and natural gas production.

On June 3, 2010, the EPA published its so-called GHG tailoring rule that will phase in federal prevention of significant deterioration permit requirements for new sources and modifications, and Title V operating permits for all sources, that have the potential to emit specific quantities of GHGs. Those permitting provisions, should they become applicable to our operations, could require controls or other measures to reduce GHG emissions from new or modified sources, and we could incur additional costs to satisfy those requirements. On November 30, 2010, the EPA published a rule establishing GHG reporting requirements for sources in the petroleum and natural gas industry, requiring those sources to monitor, maintain records on, and annually report their GHG emissions, with the first annual report for 2011 being due in September 2012. Although this rule does not limit the amount of GHGs that can be emitted, it requires us to incur costs to monitor, record keep and report GHG emissions associated with our operations.

We have identified material weaknesses in our internal control over financial reporting. These material weaknesses, if not corrected, could affect the reliability of our financial statements and have other adverse consequences.

Under Section 404 of the Sarbanes-Oxley Act of 2002, we are required to furnish a report by our management on internal control over financial reporting. This report must contain, among other matters, an assessment of the effectiveness of our internal control over financial reporting, including a statement as to whether or not our internal control over financial reporting is effective. This assessment must include disclosure of any material weaknesses in our internal control over financial reporting identified by our management.

We have identified material weaknesses in our internal control over financial reporting as of December 31, 2012 relating primarily to the fact that we have a limited number of internal and external staff and therefore are not able to implement proper segregation of duties and review procedures. Failure to have effective internal controls could lead to a misstatement of our financial statements. If, as a result of deficiencies in our internal controls, we cannot provide reliable financial statements, our business decision process may be adversely affected, our business and operating results could be harmed, investors could lose confidence in our reported financial information, the price of our common shares could decrease and our ability to obtain additional financing, or additional financing on favorable terms, could be adversely affected. In addition, failure to maintain effective internal control over financial reporting could result in investigations or sanctions by regulatory authorities.

We intend to take action to remediate the material weaknesses and improve the effectiveness of our internal control over financial reporting. However, we can give no assurances that the measures we may take will remediate the material weaknesses identified or that any additional material weaknesses will not arise in the future due to our failure to implement and maintain adequate internal control over financial reporting. In addition, even if we are successful in strengthening our controls and procedures, those controls and procedures may not be adequate to prevent or identify irregularities or ensure the fair presentation of our financial statements included in our periodic reports filed with the SEC.

Our officers and directors are engaged in other business activities and conflicts of interest may arise in their daily activities which may not be resolved in our favor.

Certain conflicts of interest may exist between us and our officers and directors. Our officers and directors have other business interests to which they devote their attention, and we expect they will continue to do so. As a result, conflicts of interest or potential conflicts of interest may arise from time to time that can be resolved only through the officers or directors exercising such judgment as is consistent with fiduciary duties to their other business interests and to us. These conflicts of interest may not be resolved in our favor.

Compliance with changing regulation of corporate governance and public disclosure will result in additional expenses and pose challenges for our management.

Changing laws, regulations and standards relating to corporate governance and public disclosure, including the Dodd-Frank Act and the rules and regulations promulgated thereunder, the Sarbanes-Oxley Act and SEC regulations, have created uncertainty for public companies and significantly increased the costs and risks associated with accessing the U.S. public markets. Our management team will need to devote significant time and financial resources to comply with both existing and evolving standards for public companies, which will lead to increased general and administrative expenses and a diversion of management time and attention from revenue generating activities to compliance activities.

Risks Related to Our Common Stock

We may raise additional capital in the future through issuances of securities and such additional funding may be dilutive to shareholders or impose operational restrictions.

We may raise additional capital in the future to help fund our operations through sales of shares of our common stock or securities convertible into shares of our common stock, as well as issuances of debt. Such additional financing may be dilutive to our shareholders, and debt financing, if available, may involve restrictive covenants which may limit our operating flexibility, including the ability to pay dividends. If additional capital is raised through the issuances of shares of our common stock or securities convertible into shares of our common stock, the percentage ownership of existing shareholders will be reduced. These shareholders may experience additional dilution in net book value per share and any additional equity securities may have rights, preferences and privileges senior to those of the holders of our common stock.

We do not intend to pay dividends in the future.

We have not paid dividends on our common stock and do not intend to pay dividends in the foreseeable future. The payment of cash dividends in the future will be dependent on our revenues and earnings, if any, capital requirements and general financial condition and will be entirely within the discretion of our board of directors at such time. It is the present intention of our board of directors to retain earnings, if any, to fund our future growth, and there is no assurance we will ever pay dividends in the future. As a result, any gain you will realize on our securities will result solely from the appreciation of such securities.

Because we are quoted on the OTC Bulletin Board instead of an exchange or national quotation system, our investors may have more difficulty selling their stock or may experience negative volatility in the market price of our stock.

Our common stock is traded on the OTCBB, which is subject to greater volatility than a national exchange or quotation system. This volatility may be caused by a variety of factors, including the lack of readily available price quotations, the absence of consistent administrative supervision of bid and ask quotations, lower trading volume, and market conditions. Investors in our common stock may experience high fluctuations in the market price and volume of the trading market for our securities. These fluctuations, when they occur, have a negative effect on the market price for our common stock. Accordingly, our stockholders may not be able to realize a fair price from their shares when they determine to sell them or may have to hold them for a substantial period of time until the market for our common stock improves.

Trading in our common stock has been limited, and our stock price could potentially be subject to substantial fluctuations.

Trading in our common stock has been limited. Historically, our stock price has been affected substantially by a relatively modest volume of transactions and could be again so affected. If our stock price falls, our stockholders may not be able to sell their stock when desired or at desirable prices.

The value of our common stock might be affected by matters not related to our own operating performance.

The value of our common stock may be affected by matters that are not related to our operating performance and which are outside of our control. These matters include the following:

- general domestic and worldwide economic conditions;

- industry conditions, including fluctuations in the price of oil and natural gas;
- governmental regulation of the oil and natural gas industry, including environmental regulation and regulation of fracture stimulation activities;
- liabilities inherent in oil and natural gas operations;
- geological, technical, drilling and processing problems;
- unanticipated operating events which can reduce production or cause production to be shut in or delayed;
- failure to obtain industry partner and other third party consents and approvals, when required;
- stock market volatility and market valuations;

- competition for, among other things, capital, acquisition of reserves, undeveloped land and skilled personnel;
- political conditions in oil and natural gas producing regions;
- revenue and operating results failing to meet expectations in any particular period;
- investor perception of the oil and natural gas industry;
- limited trading volume of our common stock;
- announcements relating to our business or the business of our competitors;
- the sale of assets;
- our liquidity; and
- our ability to raise additional funds.

In the past, companies that have experienced volatility in the trading price of their common stock have been the subject of securities class action litigation. We might become involved in securities class action litigation in the future. Such litigation often results in substantial costs and diversion of management's attention and resources and could have a material adverse effect on our business, financial condition and results of operation.

Our common stock is subject to penny stock regulation.

Our shares are subject to the provisions of Section 15(g) and Rule 15g-9 of the Exchange Act, commonly referred to as the "penny stock" rule, which set forth certain requirements for transactions in penny stocks. The SEC generally defines penny stock to be any equity security that has a market price less than $5.00 per share, subject to certain exceptions. Rule 3a51-1 provides that any equity security is considered to be penny stock unless that security is: registered and traded on a national securities exchange meeting specified criteria set by the SEC; authorized for quotation on the NASDAQ Stock Market; issued by a registered investment company; excluded from the definition on the basis of price (at least $5.00 per share) or the registrant's net tangible assets; or exempted from the definition by the SEC. Since our shares are deemed to be "penny stock", trading in the shares will be subject to additional sales practice requirements on broker-dealers who sell penny stock to persons other than established customers and accredited investors.

FINRA Sales Practice requirements may also limit a stockholder's ability to buy and sell our stock.

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

33

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

All of our producing oil and natural gas properties are located in the Permian Basin of Southeastern New Mexico, in Chaves, Eddy, Lea, and Roosevelt counties. We also have significant undeveloped acreage in Chaves, De Baca, Eddy, Grant, Hidalgo, Lea, Sierra, Socorro, Roosevelt, and San Juan counties. The following is a map showing the counties in which we have acreage as of December 31, 2012.

Title to Properties

As is customary in the oil and natural gas industry, we generally conduct a preliminary title examination prior to the acquisition of properties or leasehold interests. Prior to commencement of operations on such acreage, a thorough title examination will usually be conducted and any significant defects will be remedied before proceeding with operations. We believe the title to our leasehold properties is good, defensible and customary with practices in the oil and natural gas industry, subject to such exceptions that we believe do not materially detract from the use of such properties. With respect to our properties of which we are not the record owner, we rely instead on contracts with the owner or operator of the property or assignment of leases, pursuant to which, among other things, we generally have the right to have our interest placed on record.

Our properties are generally subject to royalty, overriding royalty and other interests customary in the industry, liens incident to agreements, current taxes and other burdens, minor encumbrances, easements and restrictions. We do not believe any of these burdens will materially interfere with our use of these properties. Substantially all of our material properties are pledged as collateral under our line of credit with Independent Bank.

Summary of Oil and Natural Gas Reserves

Proved Reserves

The following table sets forth our estimated net proved reserves as of December 31, 2012.

		Reserves	
Estimated Proved Reserves Data: (1)	Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)
Proved developed reserves	804	1,336	1,027
Proved undeveloped reserves	467	359	527
Total proved reserves	1,271	1,695	1,554

(1) Prices used are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January 2012 through December 2012. For oil volumes, the average NYMEX posted price of $94.68 per Bbl is adjusted for quality, transportation fees and a regional price differential. For natural gas volumes, the average Henry Hub spot price of $2.76 per Mcf is adjusted for energy content, transportation fees and a regional price differential. The adjusted oil and natural gas prices of $87.84 per barrel and $5.13 per Mcf, respectively, are held constant throughout the lives of the properties.

The following table sets forth our estimated PV-10 and standardized measure of discounted net cash flows as of December 31, 2012.

(in thousands)	As of December 31, 2012
PV-10 (1)	$ 27,471
Standardized measure	$ 18,640

(1) PV-10 is a non-GAAP financial measure as defined by the SEC. The closest GAAP measure to PV-10 is the standardized measure of discounted net cash flows. The standardized measure differs from PV-10 because standardized measure includes the effect of future income taxes. We believe that the presentation of PV-10 is relevant and useful to our investors as supplemental disclosure to the standardized measure, or after-tax amount, because it presents the discounted future net cash flows attributable to our proved reserves before taking into account future corporate income taxes and our current tax structure. The following table provides a reconciliation of our PV-10 to our standardized measure:

(in thousands)	
PV-10	$ 27,471
Future income taxes	(12,218)
Discount of future income taxes at 10% per annum	3,369
Standardized measure	$ 18,640

Estimates of proved developed and undeveloped reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors. See "—Qualifications of Technical Persons and Internal Controls Over Reserves Estimation Process."

At December 31, 2012, our estimated proved reserves were 1,554 MBoe, a decrease of 26.2% compared to 2,106 MBoe at December 31, 2011. During 2012, we added estimated proved reserves of 210 MBoe through extensions and discoveries. The additions were offset by production of 200 MBoe, sales of 168 Mboe, and downward revisions in previous estimates of 394 MBoe. The downward revisions were primarily attributable to an updated analysis of capital and operating expenses for all properties. The largest impact was a reduction of the number of proved undeveloped wells in the Tom Tom prospect.

Proved Undeveloped Reserves

Our proved undeveloped reserves at December 31, 2012 were 527 MBoe, consisting of 467 MBbls of oil and 359 MMcf of natural gas. During 2012, we converted 125 MBoe of proved undeveloped reserves to proved developed producing reserves, primarily due to the completion of development wells in the Lusk and Turkey Track prospects in the 2nd Bone Springs formation. As of December 31, 2012, estimated future development costs relating to the development of our proved undeveloped reserves was $14.2 million. All of our currently identified proved undeveloped reserves are scheduled to be drilled by December 31, 2015.

Qualifications of Technical Persons and Internal Controls Over Reserves Estimation Process

Our reserve report was prepared by Joe C. Neal & Associates ("Neal"), independent petroleum engineers. Neal estimated, in accordance with petroleum engineering and evaluation principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information promulgated by the Society of Petroleum Engineers ("SPE Standards") and definitions and guidelines established by the SEC, 100% of the proved reserve information for our properties as of December 31, 2012.

The technical persons responsible for preparing the reserves estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Natural Gas Reserves Information promulgated by the Society of Petroleum Engineers.

The principal person at Neal who prepared the reserve report for the Company is Joe C. Neal, P.E., owner of Joe C. Neal and Associates. Mr. Neal began his career with Gulf Oil in 1956, managing large waterflood projects and performing reservoir engineering valuations in the Permian Basin. He worked as a Senior Evaluation Engineer at other consulting firms before founding his own company in 1983. Mr. Neal holds a B.S. in Mechanical Engineering with Petroleum Option from the Oklahoma State University. He is a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers and is a registered professional engineer in the State of Texas.

As indicated elsewhere in this report, we have no full-time employees and instead rely on the availability of internal staff of Red Mountain, the majority holder of our common stock, to assist us in working with our independent petroleum engineers to ensure the integrity, accuracy and timeliness of data furnished to them in their reserves estimation process. Our technical team consults regularly with representatives of Neal. We review with them our properties and discuss methods and assumptions used in their preparation of our year-end reserves estimates. While we have no formal committee specifically designated to review reserves reporting and the reserves estimation process, a copy of the reserve report is reviewed with representatives of Neal and our internal technical staff before we disseminate any of the information. Additionally, our senior management reviews and approves the Neal reserve report and any internally estimated significant changes to our proved reserves on an annual basis.

Estimates of oil and natural gas reserves are projections based on a process involving an independent third party engineering firm's collection of all required geologic, geophysical, engineering and economic data, and such firm's complete external preparation of all required estimates and are forward-looking in nature. These reports rely upon various assumptions, including assumptions required by the SEC, such as constant oil and natural gas prices, operating expenses and future capital costs. The process also requires assumptions relating to availability of funds and timing of capital expenditures for development of our proved undeveloped reserves. These reports should not be construed as the current market value of our reserves. The process of estimating oil and natural gas reserves is also dependent on geological, engineering and economic data for each reservoir. Because of the uncertainties inherent in the interpretation of this data, we cannot be certain that the reserves will ultimately be realized. Our actual results could differ materially. See "Note 15—Supplemental Information Relating to Oil and Natural Gas Producing Activities (Unaudited)" to our audited consolidated financial statements for additional information regarding our oil and natural gas reserves.

Under SEC rules, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. To achieve reasonable certainty, Neal employs technologies consistent with the standards established by the Society of Petroleum Engineers. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps and available downhole and production data, seismic data and well test data.

Summary of Oil and Natural Gas Properties and Projects

Production, Price and Cost History

The following table presents net production sold, average sales prices and production costs and expenses for the years ended December 31, 2012 and 2011.

	Year ended December 31,	
	2012	2011
(dollars in thousands, except per unit prices)		
Revenue		
Oil and natural gas sales	$14,781,497	$6,584,134
Net production sold		
Oil (Bbl)	149,600	56,740
Natural gas (Mcf)	285,885	252,690
Total (Boe)	197,247	98,855
Average sales prices		
Oil ($/Bbl)	$87.95	$86.70
Natural gas ($/Mcf)	4.47	6.03
Total average price ($/Boe)	$73.19	$65.17
Costs and expenses (per Boe)		
Production taxes	$5.94	$5.41
Lease operating expenses	11.57	12.69
Natural gas transportation and marketing expenses	0.73	0.11

Developed and Undeveloped Acreage

The following table presents our total gross and net developed and undeveloped acreage as of December 31, 2012:

Developed Acres		Undeveloped Acres	
Gross (1)	Net (2)	Gross (1)	Net (2)
9,277	3,834	856,616	290,009

(1) "Gross" means the total number of acres in which we have a working interest.
(2) "Net" means the sum of the fractional working interests that we own in gross acres.

The primary terms of our oil and natural gas leases expire at various dates. Much of our developed acreage is held by production, which means that these leases are active as long as we produce oil or natural gas from the acreage or comply with certain lease terms. Upon ceasing production, these leases will expire. Additionally, we have significant undeveloped acreage which consists of mineral rights and, accordingly, does not expire.

Productive Wells

The following table presents the total gross and net productive wells by oil or natural gas completion as of December 31, 2012. We own royalty interests in 14 gross wells (average of 0.37%), which have been excluded from these well counts:

Oil Wells		Natural Gas Wells	
Gross(1)	Net(2)	Gross(1)	Net(2)
127	56.2	34	2.9

(1) "Gross" means the total number of wells in which we have a working interest.
(2) "Net" means the sum of the fractional working interests that we own in gross wells.

Drilling Activity

The following table summarizes the number of net productive and dry development wells and net productive and dry exploratory wells we drilled during the periods indicated and refers to the number of wells completed during the period, regardless of when drilling was initiated. At December 31, 2012, we had no wells being drilled and 6 gross (0.78 net) wells awaiting completion.

	Development Wells		Exploratory Wells	
Year Ended December 31,	Productive	Dry	Productive	Dry
2012	1.91	0	0.13	0
2011	0.36	0	1.17	0
2010	0.36	0.05	0.22	0

Item 3. Legal Proceedings

We are not a party to, and none of our properties are the subject of, any material pending legal proceedings, nor are we aware of any material legal proceedings contemplated by any government authority.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Our common stock is quoted on the OTCBB under the symbol "XBOR." The following table sets forth the range of high and low bid prices for our common stock for the periods indicated. The over-the-counter market quotations reflect inter-dealer prices, without retail mark-up, mark-down or commission and may not necessarily represent actual transactions.

	High	Low
Fiscal Year 2012:		
Fourth Quarter	$ 1.25	$ 0.86
Third Quarter	$ 1.62	$ 1.10
Second Quarter	$ 1.99	$ 1.50
First Quarter	$ 2.70	$ 1.55
Fiscal Year 2011:		
Fourth Quarter	$ 1.68	$ 1.30
Third Quarter	$ 2.24	$ 1.15
Second Quarter	$ 2.75	$ 1.55
First Quarter	$ 4.70	$ 2.00

Holders

As of April 1, 2013, there were approximately 42 holders of reocrd of our common stock, including nominee holders such as bank and brokerage firms who hold shares for beneficial owners.

Dividends

We have not paid any cash dividends on our common stock to date. The payment of any dividends is within the discretion of our Board of Directors. However, our credit agreement with Independent Bank restricts our ability to pay dividends. Accordingly, it is the present intention of the Board of Directors to retain all earnings, if any, for use in the business operations and, accordingly, the Board does not anticipate declaring any dividends in the foreseeable future. The payment of dividends in the future, if any, will be contingent upon restrictions contained in our credit agreement, our revenues and earnings, if any, capital requirements and our general financial condition.

Sales of Unregistered Securities

We have not made any sales of unregistered securities during the year ended December 31, 2012 that was not disclosed previously in a Quarterly Report on Form 10-Q or in a Current Report on Form 8-K.

Item 6. Selected Financial Data

Not applicable.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and the related notes to those statements included elsewhere in this Annual Report on Form 10-K. In addition to historical financial information, the following discussion and analysis contains forward-looking statements that involve risks, uncertainties and assumptions. Our results and the timing of selected events may differ materially from those anticipated in these forward-looking statements as a result of many factors, including those discussed under "Risk Factors" and elsewhere in this Annual Report on Form 10-K.

Company

We are an oil and gas exploration company. We currently own over 865,893 gross (approximately 293,843 net) mineral and lease acres in New Mexico and Texas. Approximately 25,000 of these net acres exist within the Permian Basin. A significant majority of our acreage consists of either owned mineral rights or leases held by production, allowing us to hold lease rental payments to under $5,000 annually. The majority of our acreage interests consists of non-operated working interests except for certain core San Andres properties which we operate.

Current development of our acreage is focused on our prospective Bone Spring acreage located in the heart of the 1st and 2nd Bone Spring play. This play encompasses approximately 4,390 square miles across both New Mexico and Texas. We currently own varying, non-operated working interests in both Eddy and Lea Counties, New Mexico, along with our working interest partners that include Cimarex, Apache, Oxy Permian, Occidental, Oxy USA and, Mewbourne; all having significant footprints within this play, and are adding to those footprints through lease and corporate acquisitions.

History

We were originally formed on October 25, 2005 under the name "Language Enterprises Corp." We subsequently changed our name to Doral Energy Corp. On July 29, 2008, we acquired a working interest in 66 producing oil fields and approximately 186 wells (the "Eddy County Properties") in and around Eddy County, New Mexico. As a result of our acquisition of the Eddy County Properties, we changed our business focus to the acquisition, exploration, operation and development of oil and gas projects, and we ceased being a "shell company." On August 4, 2008, we filed our Form 8-K that included the information that would be required if we were filing a general form for registration of securities on Form 10 as a smaller reporting company.

Effective January 3, 2011, we completed the acquisition of Pure Energy Group, Inc. as contemplated pursuant to the Pure Merger Agreement among our company, Doral Sub, Pure L.P. and Pure Sub, a wholly owned subsidiary of Pure L.P. Pursuant to the provisions of the Pure Merger Agreement, all of Pure L.P.'s oil and gas assets and liabilities were transferred to Pure Sub. Pure Sub was then merged with and into Doral Sub, with Doral Sub continuing as the surviving corporation. Upon completion of the Pure Merger, the outstanding shares of Pure Sub were converted into an aggregate of 9,981,536 shares of our common stock. Since the Pure Merger, Pure L.P. has distributed all of its shares of our common stock to the partners of Pure L.P. so that Pure L.P. is no longer a shareholder of our company.

Effective January 4, 2011, following closing of the Pure Merger, Doral Sub was merged with and into our company, with our company continuing as the surviving corporation. Upon completing the merger of Doral Sub with and into our company, we changed our name to "Cross Border Resources, Inc."

Significant Fiscal 2012 Operations

Cross Border Resources, Inc. is an oil and gas exploration company resulting from the business combination of Doral Energy Corp. and Pure Gas Partners II, L.P. ("Pure L.P."), effective January 3, 2011. We own over 865,893 gross (approximately 293,843 net) mineral and lease acres in New Mexico and Texas. Approximately 25,000 of these net acres exist within the Permian Basin. A significant majority of our acreage consists of either owned mineral rights or leases held by production, allowing us to hold lease rental payments to under $5,000 annually. The majority of our acreage interests consists of non-operated working interests except for certain core San Andres producing properties in Chaves and Roosevelt Counties and an emerging Cherry Canyon/Brushy Canyon producing properties in Lea County which we operate.

Current development of our acreage is focused on our prospective Bone Spring acreage located in the heart of the 1st and 2nd Bone Spring play. This play encompasses approximately 4,390 square miles across both New Mexico and Texas. We currently own varying, non-operated working interests in both Eddy and Lea Counties, New Mexico, along with our working interest partners that include Cimarex, Apache, Oxy Permian, Occidental, Oxy USA and Mewbourne, all having significant footprints within this play, and are adding to those footprints through lease and corporate acquisitions.

Successful 2nd Bone Spring and Yeso horizontal and vertical completions during 2012 have been instrumental in increasing our net daily production to a net daily production rate of approximately 426 boepd for the fourth quarter of 2012. The net daily production rate has dropped from 675 boepd in March 2012 due to the normal decline of new wells put on production during the first quarter of 2012, storage and facility limitations on these wells,fewer new high impact wells coming on during the second half of 2012, and the sale of assets.

Additional development is currently underway on our Yeso and Bone Springs acreage with our other working interest partners Apache, Marshall & Winston, Concho Resources, Cimarex, Mewborne, Oxy Permian, Occidental and OXY USA. We currently have a drilling inventory across these formations with varying non-operated working interests ranging from 1.05% to 43.75%. In the coming months, management intends to place greater emphasis on our operated properties, primarily in the Tom Tom/Tomahawk area, where we have working interests ranging from 37% to 100%.

During 2012, we participated in 27 gross (2.6 net) new wells. In the months of July and August, we participated in 7 gross (0.75 net) new wells. Of these 27 wells, as of December 31, 2012, 21 had been placed on production, while 6 are awaiting completion. Additionally, all 4 of wells that were drilled during 2011 and were awaiting completion at year end 2011 were successfully completed during 2012.

In August 2012, we sold all of our Wolfberry assets located in the Texas counties of Dawson, Howard, Martin and Borden to Big Star Oil and Gas, LLC for $2.25 million in cash. An impairment of approximately $1.8 million was recorded in June 2012 to reduce the carrying value of these assets to the sales price. The average production from this area was approximately 29 boepd, which was replaced by new production from other areas.

Planned Operations

We plan to spend between $8 million and $12 million during fiscal 2013 to drill and complete wells, re-enter and complete wells, or improve infrastructure. Our main area of focus is the Tom Tom/Tomahawk Prospect, where we will begin work on the field alongside the execution of our remediation plan. For fiscal 2013, this includes the re-entry of 14 gross wells (11.7 net), drilling of 6 gross wells (5.2 net), and the improvement of field infrastructure. We will also spend capital in several non-operated prospect areas. Currently, we are committed to participating in the drilling of 12 gross wells (1.1 net) in fiscal 2013

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations is based upon our consolidated financial statements, which have been prepared in accordance with U.S. generally accepted accounting principles ("GAAP"). The preparation of these consolidated financial statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenue and expenses, and related disclosures. Our significant accounting policies are described in "Note 3—Summary of Significant Accounting Policies" to our consolidated financial statements included in this Annual Report on Form 10-K. We have identified below policies that are of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management. These estimates are based on historical experience, information received from third parties, and on various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates under different assumptions or conditions.

We believe the following critical accounting policies affect the significant judgments and estimates used in the preparation of our consolidated financial statements.

Oil and Gas Properties

We follow the successful efforts method of accounting for our oil and natural gas producing activities. Costs to acquire mineral interests in oil and natural gas properties and to drill and equip development wells and related asset retirement costs are capitalized. Costs to drill exploratory wells are capitalized pending determination of whether the wells have proved reserves. If we determine that the wells do not have proved reserves, the costs are charged to expense. There were no exploratory wells capitalized pending determination of whether the wells have proved reserves at December 31, 2012 or 2011. Geological and geophysical costs, including seismic studies and costs of carrying and retaining unproved properties, are charged to expense as incurred. We capitalize interest on expenditures for significant exploration and development projects that last more than six months while activities are in progress to bring the assets to their intended use. Through December 31, 2012, we had capitalized no interest costs because our exploration and development projects generally lasted less than six months. Costs incurred to maintain wells and related equipment are charged to expense as incurred.

On the sale or retirement of a complete unit of a proved property, the cost and related accumulated depreciation, depletion and amortization are eliminated from the property accounts, and the resultant gain or loss is recognized. On the retirement or sale of a partial unit of proved property, the cost is charged to accumulated depreciation, depletion and amortization, with a resulting gain or loss recognized in income.

Capitalized amounts attributable to proved oil and natural gas properties are depleted by the unit-of-production method over proved reserves using the unit conversion ratio of six Mcf of natural gas to one Boe. The ratio of six Mcf of natural gas to one Boe is based on energy equivalency, rather than price equivalency. Given current price differentials, the price for a Boe for natural gas differs significantly from the price for a barrel of oil.

It is common for operators of oil and natural gas properties to request that joint interest owners pay for large expenditures, typically for drilling new wells, in advance of the work commencing. This right to call for cash advances is typically found in the operating agreement that joint interest owners in a property adopt. We record these advance payments in prepaid and other current assets in its property account and release this account when the actual expenditure is later billed to it by the operator.

On the sale of an entire interest in an unproved property for cash or cash equivalents, gain or loss on the sale is recognized, taking into consideration the amount of any recorded impairment if the property had been assessed individually. If a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained.

Impairment of Long-Lived Assets

We evaluate our long-lived assets for potential impairment in their carrying values whenever events or changes in circumstances indicate such impairment may have occurred. Oil and natural gas properties are evaluated for potential impairment by field. Other properties are evaluated for impairment on a specific asset basis or in groups of similar assets, as applicable. An impairment on proved properties is recognized when the estimated undiscounted future net cash flows of an asset are less than its carrying value. If an impairment occurs, the carrying value of the impaired asset is reduced to its estimated fair value, which is generally estimated using a discounted cash flow approach. If the results of an assessment indicate that the properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized.

Unproved oil and natural gas properties do not have producing properties. As reserves are proved through the successful completion of exploratory wells, the cost is transferred to proved properties. The cost of the remaining unproved basis is periodically evaluated by management to assess whether the value of a property has diminished. To do this assessment, management considers estimated potential reserves and future net revenues from an independent expert, our history in exploring the area, our future drilling plans per our capital drilling program prepared by our reservoir engineers and operations management and other factors associated with the area. Impairment is taken on the unproved property cost if it is determined that the costs are not likely to be recoverable. The valuation is subjective and requires management to make estimates and assumptions which, with the passage of time, may prove to be materially different from actual results.

In the second quarter of 2012, the Company determined to sell its Wolfberry assets located in Texas. As a result of that decision, management conducted an impairment evaluation of those assets which resulted in a non cash impairment charge of approximately $1,776,000.

Additionally, during the fourth quarter of 2012, management conducted an impairment evaluation of its proved and unproved oil and natural gas properties. As a result of the evaluation, management recorded a non cash impairment charge of approximately $857,945, primarily related to a decline in the value of proved reserves.

Recent Accounting Pronouncements

In May 2011, the FASB issued an accounting pronouncement related to fair value measurement (FASB ASC Topic 820), which amends current guidance to achieve common fair value measurement and disclosure requirements in U.S. GAAP and International Financial Reporting Standards. The amendments generally represent clarification of FASB ASC Topic 820, but also include instances where a particular principle or requirement for measuring fair value or disclosing information about fair value measurements has changed. This pronouncement is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. We adopted this pronouncement for our fiscal year beginning January 1, 2012 and the adoption of this pronouncement did not have a material effect on our consolidated financial statements.

In December 2011, the Financial Accounting Standards Board ("FASB") issued new standards that require an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. The new standards are effective for annual periods beginning on or after January 1, 2013. We are currently evaluating the provisions of the new standards and assessing the impact, if any, it may have on our financial position and results of operations.

In January 2010, the FASB issued new standards intended to improve disclosures about fair value measurements. The new standards require details of transfers in and out of Level 1 and Level 2 fair value measurements and the gross presentation of activity within the Level 3 fair value measurement roll forward. The new disclosures are required of all entities that are required to provide disclosures about recurring and nonrecurring fair value measurements. We adopted these new rules effective January 1, 2010.

Results of Operations

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

The following table sets forth summary information regarding our oil and natural gas sales, net production sold, average sales prices and production costs and expenses for the fiscal years ended December 31, 2012 and 2011.

	Year Ended December 31, 2012	2011
(dollars in thousands, except per unit prices)		
Revenue		
Oil and natural gas sales	$14,781,497	$6,584,134
Net Production sold		
Oil (Bbl)	149,600	56,740
Natural gas (Mcf)	285,885	252,690
Total (Boe)	197,247	98,855
Total (Boe/d) (1)	539	271
Average sales prices		
Oil ($/Bbl)	$87.95	$86.70
Natural gas ($/Mcf)	4.47	6.03
Total average price ($/Boe)	$73.19	$65.17
Costs and expenses (per Boe)		
Operating costs	$11.57	$14.52
Environmental cleanup	10.65	—
Natural gas marketing and transportation expenses	0.73	0.10
Impairment expense	13.35	0.50
Production taxes	5.94	5.62
Depreciation, depletion, and amortization	28.75	21.30
Gain on sale of oil and gas properties	—	(6.06)
Accretion of discount on asset retirement obligation	0.48	0.85
General and administrative expense	14.45	37.07

______

(1) Boe/d is calculated based on actual calendar days during the period.

Revenues and Production

Oil and Natural Gas Production. During the year ended December 31, 2012, we had total production of 197,247 Boe, compared to total production of 98,855 Boe during the year ended December 31, 2011. The increase in total production was attributable to new sales from the wells as indicated in the table below, offset by natural declines in existing wells. For the year ended December 31, 2012, 75.8% of our production was oil and 24.2% was natural gas, compared to 57.4% oil and 42.6% natural gas for the year ended December 31, 2011.

Well Name	2012 Oil Produced (Bbls)	2012 Gas Produced (Mcf)	2012 BOE Produced
Bradley 29 Fed Com 3-H	811	1,269	1,022
Bradley 30 Fed Com 1-H	3,877	9,551	5,468
Bradley 30 Fed Com 2-H	1,295	2,466	1,706
Bradley 30 Fed Com 3-H	483	631	588
Buck Baker 15 #2	2,397	3,369	2,959
Coleman 10 #2	863	507	948
Fecta 33 Fed Com 1-H	11,719	6,883	12,867
Grave Digger State 3-H	1,323	875	1,469
Hefley 24 #1	1,269	4,321	1,974
High Lonesome 26 2-H	572	2,728	1,026
Leo 3 Fed Com 1-H	10,997	4,715	11,753
Leo 3 Fed Com 2-H	2,110	2,606	2,544
Little Eddy Unit #5 A	519	85	533
Lusk SE Fed Com 33 2-H	22,497	22,774	26,292
Lusk SE Fed Com 33 3-H	31,307	22,225	35,012
Lusk SE Fed Com 34 2-H	713	2,065	1,057
Ocelot Fed Com 34 1-H	4,838	4,378	5,567
Roo 22 State #7	693	105	711
Zircon 2 State 1-H	8,040	14,261	10,416
Zircon 2 LI State 1-H	6,037	6,073	7,050
Totals	112,360	111,887	130,962

Oil and Natural Gas Sales. During the year ended December 31, 2012, we had oil and natural gas sales of $14.8 million, as compared to $6.6 million during the year ended December 31, 2011. The increase in oil and natural gas sales was attributable to the completion and bringing online of new wells as indicated in the table above, offset by natural declines in existing wells.

Costs and Expenses

Operating Costs. During the year ended December 31, 2012, we incurred operating costs of $2.3 million, as compared to $1.4 million during the year ended December 31, 2011. The increase in operating costs can be attributed to the completion and bringing online of new wells during the year. In addition, we incurred approximately $0.8 million to recomplete three salt water disposal wells in which we own a 100% working interest.

Environmental Cleanup. For the year ended December 31, 2012 we incurred a $2.1 million non-cash charge related to required environmental remediation activities on our Tom Tom / Tomahawk field. There were no such charges in the year ended December 31, 2011.

Impairment. For the year ended December 31, 2012, impairment expense was $2.6 million compared to approximately $49,000 for the year ended December 31, 2011. We incurred a $1.8 million impairment charge related to our Wolfberry assets which were sold effective August 1, 2012. Further, due to the decline in the value of our reserves, we incurred an approximately $0.8 million impairment charge in the fourth quarter.

Production Taxes. Production taxes were $1.2 million for the year ended December 31, 2012, as compared to $0.6 million for the year ended December 31, 2011. The increase in production taxes was attributable to increased production from the completion and bringing online of new wells during the year.

Depreciation, Depletion, and Amortization. For the year ended December 31, 2012, depreciation, depletion, and amortization was $5.7 million, as compared to $2.1 million for the year ended December 31, 2011. The increase in depreciation, depletion, and amortization was attributable to increased production and a higher rate of depletion in 2012 due to overall lower reserve volumes.

General and Administrative Expense. General and administrative expense was $2.9 million for the year ended December 31, 2012, as compared to $3.7 million for the year ended December 31, 2011. In general, G&A expenditures were dramatically lower year over year. Professional fees were lower by $0.7 million in 2012 as compared to the prior year. In May 2012, our former Chief Executive Officer and former Chief Operations Officer resigned their positions. Further, effective July 31, 2012, our former Chief Accounting Officer resigned her position. Accordingly, personnel costs were $0.4 million lower in 2012 than in 2011. There was no stock based compensation in 2012 while in 2011 we incurred $0.5 million in stock based compensation expenditures. These reduction in expenditures were offset by $0.9 million related to change in control payments made to our former officers and employees. There were no change of control expenditures in the year ended December 31, 2011.

Other Expense. Other expense was $0.2 million for the year ended December 31, 2012, as compared to $0.3 million for the year ended December 31, 2011. The decrease in other expense is related to an increase in bond issuance amortization, an increase in interest expense, and a decrease in other income offset by an increase in gain on our derivatives contracts.

Liquidity and Capital Resources

General

Our primary sources of liquidity are cash flow from operations and borrowings under our line of credit. Our ability to fund planned capital expenditures and to make acquisitions depends upon our future operating performance, availability of borrowings under our line of credit and availability of equity and debt financing, which is affected by prevailing economic conditions in our industry and financial, business and other factors, some of which are beyond our control. Our cash flow from operations is mainly influenced by the prices we receive for our oil and natural gas production and the quantity of oil and natural gas we produce. Prices for oil and natural gas are affected by national and international economic and political conditions, national and global supply and demand for hydrocarbons, seasonal weather influences and other factors beyond our control.

Capital Expenditures

Most of our capital expenditures are for the exploration, development, and production of oil and natural gas reserves. For 2012, we had capital expenditures of approximately $13 million for the development of oil and natural gas properties. We anticipate capital expenditures of between $8.0 million and $12.0 million for 2013. See "—Planned Operations" for more information about our planned capital expenditures.

Liquidity

At December 31, 2012, we had $0.2 million in cash and cash equivalents, $8.75 million outstanding under our line of credit with Texas Capital Bank ("TCB"), $0.760 million in in subordinated unsecured debt, and $1.4 million due to bankruptcy creditors. At December 31, 2012, our line of credit with TCB was fully drawn. At December 31, 2012, we had a working capital deficit of $3.3 million compared to a working capital deficit of $40,000 at December 31, 2011.

On February 5, 2013, we entered into a Senior First Lien Secured Credit Agreement with Independent Bank. Our initial draw on the line of credit was $8.9 million which was primarily used to pay off the TCB line of credit principal and accrued interest. On February 28, 2013, we drew another $2.0 million on the line of credit and utilized those funds to pay for capital expenditures associated with our drilling activity.

In February 2013, we settled certain creditors liabilities for $633,975 in cash and by arranging for our largest shareholder, Red Mountain, to issue the creditors an aggregate of 745,854 shares of its common stock. Further, Red Mountain, the holder of the subordinated unsecured debt, elected to convert the entire principal and accrued interest balance of the notes into 611,630 shares of our common stock.

Financings

As the result of the sale of certain interests in oil and gas properties, effective August 1, 2012, the borrowing base was reduced by $750,000 and that amount was repaid to TCB out of the sale proceeds.

47

Cash Flows

Net cash provided by operating activities was $7.0 million for the year ended December 31, 2012, compared to net cash used by operating activities of $2.9 million for the year ended December 31, 2011. The increase in net cash provided by operating activities was primarily due to a $2.4 million loss, offset by $8.7 million of non-cash depreciation, depletion, amortization and impairment, and $2.1 million non-cash environmental liability cleanup charge.

Net cash used in investing activities increased to $10 million for the year ended December 31, 2012 from $2.1 million for the year ended December 31, 2011 due to an increase in capital expenditures for the continued development of our oil and natural gas properties, offset by the receipt of approximately $2.3 million as proceeds from the sale of some of our oil and natural gas properties.

During the year ended December 31, 2012, net cash provided by financing activities was $2.8 million, as compared to $4.5 million during the year ended December 31, 2011. Net cash provided by financing activities during the year ended December 31, 2012 was primarily comprised of $7.1 million drawn under our line of credit, offset by repayments of our line of credit of $0.8 million, repayments of bonds of $3.4 million, and repayments to creditors of $0.2 million.

Indebtedness

Notes Payable- Green Shoe

In connection with the Pure Merger, the Company, as the accounting acquirer, assumed an unsecured loan from Green Shoe Investments Ltd. ("Green Shoe") in the principal amount of $487,000 at an interest rate of 5.0%

On April 26, 2011, the Company entered into a Loan Agreement with Green Shoe, and the Company executed and delivered a Promissory Note to Green Shoe in connection therewith. The amount of the Promissory Note and the loan from Green Shoe (the "Green Shoe Loan") was $550,936 and the purpose of the Green Shoe Loan was to consolidate and extend all of the loans owed by the Company and its predecessors to Green Shoe including without limitation the following: (i) loan dated May 9, 2008 in the principal amount of $100,000, (ii) loan dated May 23, 2008 in the principal amount of $150,000, (iii) loan dated July 18, 2008 in the principal amount of $50,000, (iv) loan dated February 24, 2009 in the principal amount of $100,000, and (v) loan dated April 29, 2009 in the principal amount of $87,000 plus accrued interest of $63,936. The Green Shoe Loan is unsecured.

Beginning March 31, 2011 (the effective date of the Promissory Note), the amounts owed under the Promissory Note began to accrue interest at a rate of 9.99%, and the Promissory Note provided that no payments of principal or interest were due until the maturity date of September 30, 2012. The Company was obligated to pay all accrued interest and make a principal payment equal to one-third of the principal owed upon the closing of an equity offering resulting in a specified amount of net proceeds to the Company. In addition, Green Shoe was granted the right to convert the principal and interest owed into shares of common stock of the Company at a conversion price of $4.00 per share. The principal balance of the note as of September 30, 2012 was $367,309.

The debt and associated accrued interest were not repaid at maturity on September 30, 2012. On October 22, 2012, the Company received notice from the lender's counsel that it would be considered in default on the note beginning November 1, 2012 if the note and accrued interest were not paid in full. From November 1, 2012, the note began to accrue interest at the default rate of 18%. On November 30, 2012, Jackson Street Investors, LLC purchased the note from Green Shoe Investments. Subsequently, on December 12, 2012, Red Mountain Resources, Inc., our largest shareholder purchased the note from Jackson Street Investors, LLC. As of December 31, 2012, the note had a principal balance of $367,309 and an accrued interest balance of $62,924.

On February 28, 2013, the Company's Board of Directors approved a resolution to modify the terms of the note so that the conversion price was reduced from $4.00 to $1.50 per share, which was above the market price of the common stock on such date. On February 28, 2013, Red Mountain converted the principal balance of $367,309 and accrued interest balance of $73,611 into 293,947 shares of the Company's common stock.

Notes Payable- Little Bay

In connection with the Pure Merger, the Company, as the accounting acquirer, assumed an unsecured loan from Little Bay Consulting SA ("Little Bay") in the principal amount of $520,000 at an interest rate of 5%.

On April 26, 2011, the Company entered into a Loan Agreement with Little Bay, and the Company executed and delivered a Promissory Note to Little Bay in connection therewith. The amount of the Promissory Note and the loan from Little Bay (the "Little Bay Loan") was $595,423 and the purpose of the Little Bay Loan was to consolidate and extend all of the loans owed by the Company and its predecessors to Little Bay including without limitation the following: (i) loan dated March 7, 2008 in the original principal amount of $220,000, (ii) loan dated July 18, 2008 in the original principal amount of $100,000, and (iii) loan dated October 3, 2008 in the principal amount of $200,000 plus accrued interest of $75,423. The Little Bay Loan is unsecured.

Beginning March 31, 2011 (the effective date of the Promissory Note), the amounts owed under the Promissory Note began to accrue interest at a rate of 9.99%, and the Promissory Note provided that no payments of principal or interest were due until the maturity date of September 30, 2012. The Company was obligated to pay all accrued interest and make a principal payment equal to one-third of the principal owed upon the closing of an equity offering resulting in a specified amount of net proceeds to the Company. In addition, Little Bay was granted the right to convert the principal and interest owed into shares of common stock of the Company at a conversion price of $4.00 per share. The principal balance of the note as of September 30, 2012 is $396,969.

The debt and associated accrued interest were not repaid at maturity on September 30, 2012. On October 22, 2012, the Company received notice from the lender's counsel that it would be considered in default on the note beginning November 1, 2012 if the note and accrued interest were not paid in full. From November 1, 2012, the note began to accrue interest at the default rate of 18%. On November 30, 2012, Jackson Street Investors, LLC purchased the note from Little Bay Consulting, S.A. Subsequently, on December 12, 2012, Red Mountain Resources, Inc., our largest shareholder purchased the note from Jackson Street Investors, LLC. As of December 31, 2012, the note had a principal balance of $396,969 and an accrued interest balance of $68,005.

On February 28, 2013, the Company's Board of Directors approved a resolution to modify the terms of the note so that the conversion price was reduced from $4.00 to $1.50 per share, which was above the market price of the common stock on such date. On February 28, 2013, Red Mountain converted the principal balance of $396,969 and accrued interest balance of $79,555 into 317,683 shares of the Company's common stock.

Line of Credit

As of December 31, 2011, the borrowing base on the TCB line of credit was $4,500,000. Effective March 1, 2012, the borrowing base was increased to $9,500,000. The interest rate was calculated at the greater of the adjusted base rate or 4%. The line of credit was collateralized by producing wells and was to mature on January 14, 2014. As the result of the sale of certain interests in oil and gas properties, effective August 1, 2012, the borrowing base was reduced by $750,000 and that amount was repaid to TCB out of the sale proceeds.

As of December 31, 2012 and 2011, the outstanding balance on the TCB line of credit was $8,750,000 and $2,381,000, respectively. As of December 31, 2012, the Company was not in compliance with all covenants under its agreement with TCB.

On February 5, 2013, the Company entered into a Senior First Lien Secured Credit Agreement with Red Mountain, Black Rock Capital, Inc. and RMR Operating, LLC and Independent Bank, as Lender. Red Mountain owns approximately 79% of the outstanding common stock of Cross Border and Black Rock and RMR Operating are wholly owned subsidiaries of Red Mountain. On February 5, 2013, the Company drew $8,900,000 on the line of credit and used a portion of that draw to fully pay down the TCB line of credit.

Contractual Obligations

The following table presents a summary of our contractual obligations at December 31, 2012:

	Payments Due By Period				
(in thousands)	Less than one year	One to three years	Three to five years	More than five years	Total
Line of credit	$—	$8,750,000	$—	$—	$8,750,000
Creditors payable	758,167	594,616	—	—	1,352,783
Unsecured subordinated debt	764,278	—	—	—	764,278
Environmental cleanup	—	2,100,000	—	—	2,100,000
Asset retirement obligations	452,013	1,372,652	129,149	1,363,544	3,317,358
Operating lease obligations	42,801	—	—	—	42,801
Total	$2,017,259	$12,817,268	$129,149	$1,363,544	$16,327,220

Off-Balance Sheet Arrangements

As of December 31, 2012, we did not have any off-balance sheet arrangements as defined by Regulation S-K.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Not applicable.

Item 8. Financial Statements and Supplementary Data

Our consolidated financial statements required by this item are included in this report beginning on page F-1 and are incorporated herein by reference.

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

Not applicable.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Disclosure controls and procedures are controls and other procedures that are designed to ensure that information required to be disclosed by us in 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 in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives.

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2012 and, based on that evaluation, and as a result of the material weaknesses described below, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were not effective at the reasonable assurance level.

Management’s Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of our financial statements for external purposes in accordance with GAAP. Internal control over financial reporting includes policies and procedures that: (i) pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of our assets; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of our financial statements in accordance with GAAP, and that our receipts and expenditures are being made only in accordance with the authorizations of our management and board of directors and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

Our management, under the supervision and with the participation of our principal executive officer and principal financial and accounting officer, assessed the effectiveness of our internal control over financial reporting as of December 31, 2012 based on criteria established in Internal Control — Integrated Framework created by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, our management concluded that our internal control over financial reporting was not effective as of December 31, 2012 because of the identification of the material weaknesses identified below.

A material weakness (as defined in Rule 12b-2 under the Exchange Act) is a deficiency, or combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement in our annual or interim financial statements will not be prevented or detected on a timely basis. During the course of our assessment, management identified the following material weaknesses:

- We have a limited number of internal and external staff and therefore are not able to implement proper segregation of duties and review procedures.

This Annual Report on Form 10-K does not include an attestation report of our independent registered public accounting firm regarding internal control over financial reporting as such report is not required for non-accelerated filers.

Management’s Plan for Remediation of Our Material Weaknesses

Management will continue to review and assess our system of internal control over financial reporting as well as the new members of our accounting staff and their increased levels of accounting expertise. During this review and assessment, we will continue to implement enhancements to our system of internal controls where appropriate. Finally, we will continue to evaluate the employees and contractors involved in the preparation of our financial statements, the need to engage outside consultants with accounting and tax expertise to assist us in accounting for complex transactions and the hiring of additional accounting staff as necessary to timely prepare our financial statements. Management currently believes it will be able to remedy the material weaknesses described above over the next 12 months.

Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting that occurred during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Directors and Executive Officers

Our current directors and executive officers are as follows:

Name	Age	Position
Alan W. Barksdale	36	Non-Executive Chairman of the Board of Directors
Earl Sebring	63	Interim President
Kenneth S. Lamb	37	Chief Accounting Officer, Secretary, and Treasurer
Richard F. LaRoche Jr.	67	Director
Paul N. Vassilakos	36	Director
John W. Hawkins	66	Director
Randell K. Ford	62	Director

Alan W. Barksdale has been Non-Executive Chairman of the Board of Directors since May 2012. Mr. Barksdale has been the Chief Executive Officer and Chairman of the Board of Directors of Red Mountain Resources, Inc. since June 2011, its President since July 2012, and served as its Interim Acting Chief Financial Officer from June 2011 to August 2011. Mr. Barksdale has also been the owner and president of StoneStreet and president and manager of StoneStreet Group, advisory and management services and merchant banking firms, since 2008. Mr. Barksdale has also been the president of AWB Enterprises, Inc., a holding company, since November 2011. From January 2004 to April 2010, Mr. Barksdale served as a director in the Capital Markets Group of Crews & Associates, an investment banking firm. From August 2003 to October 2003, Mr. Barksdale served as an investment banker at Stephens Inc., an investment banking firm. From 2002 to 2003, Mr. Barksdale was an investment banker at Crews & Associates. Mr. Barksdale's experience in operating, managing, financing and investing in more than 100 wells in Louisiana, New Mexico and Texas, combined with his over ten years of capital markets experience and contacts and relationships, provides our Board of Directors with invaluable management and operational direction.

In 2004, the National Association of Securities Dealers, Inc. ("NASD") alleged that Mr. Barksdale solicited an attorney to make contributions to officials of an issuer with which Stephens Inc. was engaging in municipal securities business when Mr. Barksdale was employed as an investment banker of Stephens Inc. Without admitting or denying the allegations, Mr. Barksdale entered into an acceptance, waiver and consent decree that provided for a 30-day suspension from associating with any NASD member and a $5,000 fine.

Mr. Barksdale graduated from the University of Arkansas at Little Rock where he received a Bachelor of Business Administration with an emphasis in Finance. He is registered with FINRA, MSRB, PSA and various state securities departments throughout the US. Mr. Barksdale also holds Series 7 and Series 63 licenses.

We believe that Mr. Barksdale’s prior oil and gas experience, as well as his contacts and relationships, will bring value to the Company and make him well-qualified to serve on the Board.

Earl M. Sebring has been our Interim President since June 2012. Mr. Sebring is an exploration geologist with 35 years of experience. Since August 2000, Mr. Sebring has been the owner and President of Sebring Exploration Texas, Inc., an independent exploration company. In 1982, Mr. Sebring became an exploration geologist for Wagner and Brown, eventually becoming Exploration Manager. As Exploration Manager, Mr. Sebring was responsible for handling all foreign and domestic exploration and production efforts. This included directing exploration efforts, staffing those efforts as required, and securing outside industry funding. Mr. Sebring began his career at City Service Oil Company in 1976 where his responsibilities included ascertaining petroleum commercial prospectivity in frontier basins around the world through the use of core, log, geochemical, and out crop data. Mr. Sebring has been involved in drilling, managing, consulting or investing in locations such as the Permian Basin, Gulf Coast, Oklahoma, Southern France, Southern United Kingdom, Argentina, Columbia, Kodiak Shelf of Alaska, Philippines, Southern Australia, Louisiana, New Mexico, Oklahoma and Athabasca Tar Sands. Mr. Sebring graduated from the University of Texas in 1976, where he received a Bachelor's Degree in Geology.

Kenneth S. Lamb has been our Chief Accounting Officer, Secretary, and Treasurer since August 2012. Mr. Lamb has significant experience in corporate accounting, financial reporting, and corporate governance. From December 2008 until May 2011, he was employed by Transatlantic Petroleum, Ltd., an international oil and gas company engaged in the acquisition, exploration, development, and production of crude oil and natural gas, serving as its Director of Internal Audit from December 2008 to July 2010 and its Manager of Financial Reporting and Internal Controls from August 2010 to May 2011. From July 2007 until November 2008, Mr. Lamb was employed with the Brink's Company, a company providing security-related services for banks, retailers and other commercial and governmental customers, as Internal Audit Supervisor where he managed financial audits in numerous different countries. Mr. Lamb began his career with PricewaterhouseCoopers in 2000 and worked for KPMG from 2005 to 2006. He received a B.B.A. in Accounting and a B.A. in History from Sam Houston State University and is a licensed Certified Public Accountant.

Richard F. LaRoche Jr was appointed as a director of the Company effective January 3, 2011, upon closing of the Pure Merger. Mr. LaRoche served 27 years with National HealthCare Corporation (“NHC”) as Secretary and General Counsel and 14 years as Senior Vice President, retiring from these positions in May 2002. He has served as a Board member of NHC since 2002. Mr. LaRoche serves as a director of Lodge Manufacturing Company (privately held). He also served on the boards of National Health Investors, Inc. from 1991 through 2008, National Health Realty, Inc. from 1998 through 2007 and Trinsic, Inc. from 2004 through 2006. Mr. LaRoche continues to serve on NHC’s Board of Directors and on that Board’s Audit Committee, Nominating and Corporate Governance Committee and Compensation Committee.

He has a law degree from Vanderbilt University (1970) and an A.B. degree from Dartmouth College (1967).

Mr. LaRoche brings significant experience to this Board. He has served as both an independent board member to a large publicly-held company and acted as general counsel to that company. The Company sought a director who could provide leadership as the Company developed its policies and procedures, and Mr. LaRoche has provided that direction and leadership. Mr. LaRoche’s legal and board experience were the primary factors considered in connection with his election to the Board.

Paul N. Vassilakos has been a director since May 2012. Mr. Vassilakos has served as a director of Red Mountain Resources, Inc. since October 2011 and also served as the Company's interim President and Chief Executive Officer from February 2011 to March 2011. From November 2011 through February 2012, Mr. Vassilakos served as Chief Executive Officer, Chief Financial Officer and director of Soton Holdings Group, Inc., a publicly held company now known as Rio Bravo Oil, Inc. Mr. Vassilakos has been the assistant treasurer of Cullen Agricultural Holding Corp. ("CAH") since October 2009. CAH is a development stage agricultural company which was formed in connection with the business combination between Triplecrown Acquisition Corp. and Cullen Agricultural Technologies, Inc. in October 2009. In July 2007, Mr. Vassilakos founded Petrina Advisors, Inc., a privately held advisory firm providing investment banking services, and has served as its president since its formation. Mr. Vassilakos also founded and, since December 2006, serves as the vice president of Petrina Properties Ltd., a privately held real estate holding company. From February 2002 through June 2007, Mr. Vassilakos served as vice president of Elmsford Furniture Corp., a privately held furniture retailer in the New York area. From July 2000 through January 2002, Mr. Vassilakos was an Associate within the Greek Coverage Group of Citigroup's UK Investment Banking Division. From July 1998 through July 2000, Mr. Vassilakos was an Analyst within the Industrial Group of Salomon Smith Barney's New York Investment Banking Division. Mr. Vassilakos received a BS in finance from the Leonard N. Stern Undergraduate School of Business. Mr. Vassilakos brings extensive public company and capital markets experience, as well as his professional contacts and experience, to our Board of Directors.

John W. Hawkins was appointed as a director of the Company effective January 3, 2011, effective upon closing of the Pure Merger. Mr. Hawkins has over 30 years experience in management and accounting for NYSE listed companies. He previously served as interim CFO of Pure L.P. and Aztec Energy Partners. In 2002, he retired as VP-Treasurer of Dillard Department Stores after 28 years of service. As VP-Treasurer of Dillard's, he managed the treasury department, assisted with the annual audits, managed payroll department, tax department, accounts payable department, worker's compensation and general liability department, and the employee benefits department. He was one of the 401(k) and pension plan administrators. He was heavily involved in the acquisition of 16 companies totaling approximately $2.5 billion in revenue. Mr. Hawkins received a BBA with a major in accounting from Midwestern University. Mr. Hawkins qualifies as an audit committee financial expert. In addition, his experience with publicly traded companies and his historical knowledge of the Pure operations and assets prior to the Pure merger were significant factors that led to his election to the Board. Mr. Hawkins has served on the board of directors of the Self Insurance Institute of America, Ronald McDonald House of Little Rock, Texas,Self Insured Association, and as chairman of the advisory board of Certergy Inc.

Randell K. Ford has been a director since May 2012. Mr. Ford has worked in the oil and gas industry for over 40 years. Since 1993, Mr. Ford has been the President of R. K. Ford and Associates, Inc., a consulting firm based in the Permian Basin in Midland, Texas that specializes in drilling, engineering and completion of oil and gas wells. Currently, Mr. Ford is a partner in Western Drilling Inc., an onshore drilling services company. While serving as President, Division Drilling Engineer, Principal and various other oilfield service positions, Mr. Ford has drilled, managed, consulted or invested in over 4,000 wells located domestically in 18 states and internationally in 12 countries. Mr. Ford has also served on the board of directors of Red Mountain Resources since November 2011. Our Board of Directors benefits from Mr. Ford's operational expertise, stemming from his over 40 years of experience in the oil and gas industry.

Executive Committee

The Executive Committee is empowered to exercise all the powers and authority of the Board in the management of the business and affairs of our company, except as limited by Nevada law and our bylaws.

The Executive Committee was established on May 14, 2012. The members of the Executive Committee are Alan W. Barksdale, Paul N. Vassilakos and John W. Hawkins, with Mr. Barksdale serving as chair.

Audit Committee

The primary functions of the Audit Committee are to assist the Board of Directors of the Company in fulfilling its oversight responsibilities with respect to: (i) the Company's systems of internal controls regarding finance, accounting, legal compliance and ethical behavior; (ii) the Company's auditing, accounting and financial reporting processes generally; (iii) the Company's financial statements and other financial information provided by the Company to its stockholders, the public and others; (iv) the Company's compliance with legal and regulatory requirements; and (v) the performance of the Company's corporate audit department and independent auditors. Consistent with these functions, the Committee will encourage continuous improvement of, and foster adherence to, the Company's policies, procedures and practices at all levels.

The members of the Audit Committee are not full-time employees of the Company and may or may not be accountants or auditors by profession or experts in the fields of accounting or auditing and, in any event, do not serve in such capacity. Consequently, it is not the duty of the Committee to conduct audits or to determine that the Company's financial statements and disclosures are complete and accurate and are in accordance with generally accepted accounting principles and applicable rules and regulations.

The members of the Audit Committee are John W. Hawkins, Paul N. Vassilakos and Richard F. LaRoche, Jr. John W. Hawkins serves as chair of the Audit Committee and the Board has determined that he qualifies as an audit committee financial expert. Mr. Hawkins is independent as such term as defined by both NASDAQ Marketplace Rule 5605 and SEC Rule 10A-3(b)(1). The Audit Committee meets at least four times per year (on a quarterly basis). As part of its job to foster open communications, the Audit Committee meets in separate executive sessions without management and the Company's independent auditors to discuss any matters that the Audit Committee believes should be discussed privately.

The charter of the Audit Committee is available on the Investor Relations section of the Company's website (www.xbres.com) by clicking "Investor Relations" and then "Corporate Governance."

Nominating and Corporate Governance Committee

The purpose of the Nominating and Corporate Governance Committee is to provide assistance to the Board of Directors in identifying and recommending candidates qualified to serve as directors of the Company, to review the composition of the Board of Directors, to develop, review and recommend governance policies and principles for the Company and to review periodically the performance of the Board of Directors.

The Nominating and Corporate Governance Committee considers candidates for Board membership suggested by its members and other Board members as well as management and stockholders. The Nominating and Corporate Governance Committee among many factors, considers qualities of high personal and professional ethics, values and integrity It also examines the skills, diversity, backgrounds and experience with business and other organizations of director nominees. Also, the Nominating and Corporate Governance Committee looks for candidates with the ability and willingness to commit adequate time to, as well as a commitment to representing the long-term interests of Cross

Border.

The members of the Nominating and Corporate Governance Committee are John W. Hawkins, Paul N. Vassilakos, and Richard F. LaRoche, Jr. Mr. LaRoche serves as chair of the Nominating and Corporate Governance Committee. The Nominating and Corporate Governance Committee meets at least annually.

The charter of the Nominating and Corporate Governance Committee is available on the Investor Relations section of the Company's website (www.xbres.com) by clicking "Investor Relations" and then "Corporate Governance."

The Nominating and Corporate Governance Committee has adopted the following procedures by which security holders may recommend nominees to the Company's board of directors(as well as presenting shareholder proposals for consideration by the shareholders at the next annual meeting):

The Nominating and Corporate Governance Committee will consider all nominees and shareholder proposals presented to it in writing provided that such nominees and proposals are received by the Committee no later than the first day of the fourth quarter (October 1) of the Company's fiscal year for consideration for nomination by the Nominating and Corporate Governance Committee at the following annual shareholders' meeting to be held in or around May of the following year. Written requests should be sent to the Company's address to the attention of the Chair of the Nominating and Corporate Governance Committee.

Compensation Committee

The purpose of the Compensation Committee of the Board of Directors is to discharge the responsibilities of the Board relating to compensation of the Company's executive officers and to review and approve senior officers' compensation.

Under the Charter of the Compensation Committee, the Compensation Committee is required to meet at least annually and more frequently as necessary or appropriate. Special meetings of the Committee may be called on two hours notice by the Chairman of the Board or the Committee Chairman. A majority of the Committee constitutes a quorum and the Committee may act only on the affirmative vote of a majority of the members present at the meeting.

The members of the Compensation Committee are John W. Hawkins, Paul N. Vassilakos, and Richard F. LaRoche, Jr. Mr. Vassilakos serves as chair of the Compensation Committee.

The charter of the Compensation Committee is available on the Investor Relations section of the Company's website (www.xbres.com) by clicking "Investor Relations" and then "Corporate Governance."

Code of Ethics

In connection with the Pure Merger, we adopted a Code of Business Conduct and Ethics applicable to all of our employees and directors, including our principal executive officer and principal financial officer, which is a "code of ethics" as defined by applicable rules of the SEC. The Code of Ethics is available on the Investor Relations section of the Company's website (www.xbres.com) by clicking "Investor Relations" and then "Corporate Governance."

If we make any amendments to our Code of Ethics other than technical, administrative, or other non-substantive amendments, or grant any waivers, including implicit waivers, from a provision of our Code of Ethics to our principal executive officer and principal financial officer, or certain other finance executives, we will disclose the nature of the amendment or waiver, its effective date and to whom it applies in a Current Report on Form 8-K filed with the SEC.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act ("Section 16(a)") requires our executive officers and directors, and persons who beneficially own more than 10% of our equity securities, to file reports of ownership and changes in ownership with the SEC. Based solely on our review of Forms 3, 4 and 5 furnished to us as required under the rules of the Exchange Act, we have no knowledge of any failure to report on a timely basis any transaction required to be disclosed under Section 16(a) except for the following reports: a Form 3 filed by Red Mountain on March 13, 2012 reporting a transaction that took place on May 23, 2011, a Form 4 filed by Red Mountain on December 18, 2012 reporting a transaction that took place on December 10, 2012 and a Form 4 filed by Red Mountain reporting a transaction that took place on December 24, 2012.

Item 11. Executive Compensation

On January 3, 2011, effective with the Pure merger, we changed our fiscal year end from July 31 to December 31. The following table sets forth information concerning compensation of our Named Executive Officers for the fiscal year ended July 31, 2010, the period from August 1, 2010 to December 31, 2010, and the years ended December 31, 2011 and 2012. The Named Executive Officers are: our Interim President, our Chief Accounting Officer, Secretary, and Treasurer, our former Chairman of the Board of Directors and Chief Executive Officer, our former Chief Accounting Officer, Secretary, and Treasurer, and our former President and Chief Operations Officer.

Summary Compensation Table

Name and Principal Position	Year Ended	Salary ($)	Bonus ($)	Stock Awards ($)	All Other Compensation ($)	Total ($)
Earl M. Sebring	December 31, 2012	125,000	—	—	—	125,000
Interim President	December 31, 2011	—	—	—	91,633 (1)	91,633 (1)
Everett Willard Gray, II	December 31, 2012	83,333	51,475	152,000 (2)	245,649 (2)	532,457
Former Chairman of the	December 31, 2011	200,000	72,500	278,348	118,384	669,232
Board of Directors and	December 31, 2010	75,000	0	0	5,244	80,244
Chief Executive Officer	July 31, 2010	180,000	0	0	12,586	192,586
Lawrence J. Risley	December 31, 2012	83,333	87,250	—	424,912 (3)	595,495
Former President and,	December 31, 2011	200,000	106,250	145,326	41,135	492,711
Chief Operations Officer	December 31, 2010	186,320	12,500	0	8,594	207,414
Kenneth S. Lamb Chief Accounting Officer, Secretary, and Treasurer	December 31, 2012	—	—	—	57,695 (4)	57,695 (4)
Nancy S. Stephenson	December 31, 2012	92,500	3,750	—	62,250	158,500
Former Chief Accounting Officer, Secretary, and Treasurer	December 31, 2011	42,917	5,000	0	15,650	63,567

(1) Represents amounts paid to Mr. Sebring in 2011 in consideration of Mr. Sebring providing geological consulting services to the Company through his wholly-owned company Sebring Exploration of Texas, Inc.

(2) Represents $239,149 paid to Mr. Gray under the change of control clause in his employment agreement and an auto allowance of $6,500. In November 2012, Mr. Gray agreed to forgo the remaining $239,149 owed to him under the change of control clause of his employment agreement in exchange for 150,000 shares of the Company's stock. On the date of issuance, the stock had a value of $152,000 which is report under stock awards.

(3) Represents $424,912 paid to Mr. Risley pursuant to the change of control clause in his employment agreement.

(4) Mr. Lamb is an employee of Red Mountain Resources, the Company's largest shareholder, and receives no direct remuneration from the Company. The Company reimburses Red Mountain Resources approximately $10,000 per month for the use of Mr. Lamb's services. Such amounts are reported as all other compensation in the table above.

(5) Represents $56,250 paid to Ms. Stephenson under the terms of the letter agreement pertaining to her employment with the Company and $6,000 for accrued vacation owed to her upon her resignation. In December 2012, Ms. Stephenson agreed to forgo $18,750 of her change of control payment.

Employment Agreements

Nature of Services Provided by Earl Sebring and Kenneth Lamb

Neither Mr. Sebring nor Mr. Lamb are employees of the Company. Their service as officers of the Company can be terminated at any time by the Board of Directors. The Company pays Mr. Sebring $16,667 per month for his services as Interim President. The Company reimburses Red Mountain (the Company's largest shareholder) $10,000 per month for Mr. Lamb's services as Chief Accounting Officer, Secretary, and Treasurer. Mr. Lamb is an employee of Red Mountain, and serves as Red Mountain's Controller.

Will Gray Employment Agreement

Effective January 31, 2011, the Company entered into an Employment Agreement with Everett Willard "Will" Gray II (the "Gray Employment Agreement") to serve as the Company's Chairman and Chief Executive Officer. The initial term of the Gray Employment Agreement began on January 31, 2011, and was to continue until January 31, 2013. After such date, the Gray Employment Agreement was to automatically renew for successive one-month terms. Under the Gray Employment Agreement, Mr. Gray was paid an annual base salary equal to $200,000 and was eligible to receive such bonuses as may be determined appropriate in the sole discretion of the Company's Compensation Committee or Board of Directors from time-to-time without any obligation to do so. The Company also agreed to grant to Mr. Gray an option to purchase an aggregate of six hundred fifty thousand (650,000) shares of the Company's common stock. Mr. Gray's options were set to vest and expire as follows: 300,000 options vesting at $4.80 per share on January 31, 2011, and expiring on January 30, 2016; 125,000 options vesting at $5.28 per share on January 31, 2012, and expiring on January 30, 2017; 125,000 options vesting at $5.80 per share on January 31, 2013, and expiring on January 30, 2018; and 100,000 options vesting at $6.38 per share on January 31, 2014 and expiring on January 30, 2019. In October 2011, all of these options were purchased by the Company, for $0.10 per option share (total purchase price of $65,000) and were subsequently cancelled. Mr. Gray received a monthly automobile allowance of $1,300 and was entitled to participate in benefit plans offered by the Company.

On March 5, 2012, the Gray Employment Agreement was amended for the purpose of increasing the amount payable to Mr. Gray upon termination of the Gray Employment Agreement in certain circumstances and amending the timing of such payment upon a change in control. The Gray Employment Agreement, as amended, then provided that upon termination without Cause, upon termination by Mr. Gray for Good Reason or upon a Corporate Transaction (all as defined in the Gray Employment Agreement), Mr. Gray was to be paid the following compensation: a lump sum cash payment in an amount equal to the greater of (a) twenty four (24) months of Mr. Gray's annual base salary, and (b) the monetary equivalent of Mr. Gray's benefits for a period of twenty-four (24) months ("Gray Termination Payment"). No severance was to be paid if Mr. Gray was terminated by the Company for cause.

On April 20, 2012, the Gray Employment Agreement was again amended to allow the Company to pay the aforementioned Gray Termination Payment in four equal installments upon a Corporate Transaction, rather than in one lump sum, on the following dates: (i) ten (10) days after the Corporate Transaction, (ii) the last day of the second quarter of the Company's fiscal year, (iii) the last day of the third quarter of the Company's fiscal year, and (iv) the last day of the fourth quarter of the Company's fiscal year.

On April 23, 2012, the Company entered into a Separation Agreement and Mutual Release with Mr. Gray effective May 31, 2012, the date of Mr. Gray's resignation. The Separation Agreement and Mutual Release contains a release by Mr. Gray of any and all claims against the Company and a release and indemnification by the Company of any and all claims against Mr. Gray (other than claims for deliberately dishonest, malicious or fraudulent acts or omissions or willful violations of law).

Mr. Gray was paid $239,149 or the $478,298 due him under the Gray Employment Agreement because of Corporate Transaction that occurred on May 8, 2012. On November 8, 2012, Mr. Gray agreed to accept 150,000 shares of the Company's common stock in settlement for the remaining $239,149 owed to him under the Gray Employment Agreement.

Mr. Gray has agreed to a noncompetition and nonsolicitation agreement for the two-year period following the termination of the Gray Employment Agreement.

Larry Risley Employment Agreement

Effective January 31, 2011, the Company entered into an Employment Agreement with Lawrence J. Risley (the "Risley Employment Agreement") to serve as the Company's President and Chief Operating Officer. The initial term of the Risley Employment Agreement began on January 31, 2011, and was to continue until January 31, 2013. After such date, the Risley Employment Agreement was to automatically renew for successive one-month terms. Under the Risley Employment Agreement, Mr. Risley was paid an annual base salary equal to $200,000 and was eligible to receive such bonuses as may be determined appropriate in the sole discretion of the Company's Compensation Committee or Board of Directors from time-to-time without any obligation to do so. The Company also agreed to grant to Mr. Risley an option to purchase an aggregate of three hundred thousand (300,000) shares of the Company's common stock. Mr. Risley's options were to vest and expire as follows: 150,000 options vesting at $4.80 per share on January 31, 2011, and expiring on January 30, 2016; and 150,000 options vesting at $5.28 on January 31, 2012 and expiring on January 30, 2017. In October 2011, all of Mr. Risley's options were purchased by the Company, for $0.10 per option share (total purchase price of $30,000) and were subsequently cancelled. Mr. Risley received a monthly automobile allowance of $975.00 and was entitled to participate in benefit plans offered by the Company.

On March 5, 2012, the Risley Employment Agreement was amended for the purpose of increasing the amount payable to Mr. Risley upon termination of the Risley Employment Agreement in certain circumstances and amending the timing of such payment upon a change in control. The Risley Employment Agreement, as amended, then provided that upon termination without Cause, upon termination by Mr. Risley for Good Reason or upon a Corporate Transaction (all as defined in the Risley Employment Agreement), Mr. Risley will be paid the following compensation: a lump sum cash payment in an amount equal to the greater of (a) twenty-four (24) months of Mr. Risley's annual base salary, and (b) the monetary equivalent of Mr. Risley's benefits for a period of twenty-four (24) months ("Risley Termination Payment"). No severance was to be paid if Mr. Risley is terminated by the Company for cause.

On April 20, 2012, the Risley Employment Agreement was again amended to allow the Company to pay the aforementioned Risley Termination Payment in four equal installments upon a Corporate Transaction, rather than in one lump sum.

On April 23, 2012, the Company entered into a Separation Agreement and Mutual Release with Lawrence J. Risley effective on May 31, 2012, the date of Mr. Risley's resignation. The Separation Agreement and Mutual Release contains a release by Mr. Risley of any and all claims against the Company and a release and indemnification by the Company of any and all claims against Mr. Risley (other than claims for deliberately dishonest, malicious or fraudulent acts or omissions or willful violations of law).

Mr. Risley was paid $424,912 due him under the Risley Employment Agreement because of the Corporate Transaction that occurred on May 8, 2012.

Mr. Risley has agreed to a noncompetition and nonsolicitation agreement for the two-year period following the termination of the Risley Employment Agreement.

Terms of Employment with Nancy Stephenson

Ms. Stephenson began providing consulting services to the Company in May 2011. From that date until her appointment on August 10, 2011, the Company paid consulting fees to Ms. Stephenson equal to approximately $16,000 in the aggregate.

On August 10, 2011, Nancy S. Stephenson was appointed as the Company's Chief Accounting Officer, Treasurer and Secretary. The Company paid Ms. Stephenson a monthly salary of $10,000 per month. Ms. Stephenson received no other cash or noncash compensation and no employee benefits other than four weeks of paid vacation annually. Ms. Stephenson's employment was at-will and not for any specified term. However, on March 5, 2012, the Company issued to Ms. Stephenson a letter agreement pursuant to which the Company agreed that if her employment is terminated without cause on or before January 31, 2013 or within one year of a change in control event occurring on or before January 31, 2013, she would be paid an amount equal to six (6) months of her annual base salary. No severance is to be paid if she is terminated by the Company for cause.

On April 20, 2012, the Company entered into a revised letter agreement with Ms. Stephenson pursuant to which the Company agreed to pay to Ms. Stephenson certain amounts if she was terminated without Cause, upon her termination for Good Reason or upon a Corporate Transaction occurring on or before January 31, 2013. Upon such occurrence, she would be paid an amount equal to six (6) months of her annual base salary. This restated letter allowed the Company to pay the aforementioned amount in four equal installments, rather than in one lump sum.

On April 23, 2012, the Company entered into a Mutual Release with Nancy S. Stephenson. The Mutual Release contains a release by Ms. Stephenson of any and all claims against the Company and a release and indemnification by the Company of any and all claims against Ms. Stephenson (other than claims for deliberately dishonest, malicious or fraudulent acts or omissions or willful violations of law).

Ms. Stephenson resigned as our Chief Accounting Officer, Treasurer, and Secretary effective July 31, 2012.

The Company paid Ms. Stephenson $56,250 of the $75,000 owed to her under the letter agreement due to the Corporate Transaction that occurred on May 8, 2012. In December 2012, Ms. Stephenson agreed to forego $18,750 of the amount due to her.

Indemnification Agreements

The Company has indemnification agreements with each of its directors and officers. These agreements, among other things, require the Company to indemnify each director and officer to the fullest extent permitted by applicable law, against any and all expenses of a proceeding, in the event that such person was, is or becomes a party to or witness or other participant in such proceeding by reason of such person's service as a member of the Company's board of directors or as an officer.

Director Compensation

Our Board of Directors approved a compensation program for non-employee directors, as follows:

- Each non-employee director receives an annual cash fee of $8,000;
- Each non-employee director receives a cash fee of $500 for each telephonic meeting of the Board and committee that such director participates in;
- Each non-employee director receives a cash fee of $1,500 for each in person meeting of the Board and committee that such director participates in; and
- Each non-employee director receives a cash fee of $500 for each in person meeting held with management that such director participates in.

All directors are reimbursed for their costs incurred in attending meetings of the Board of Directors or of the committees on which they serve. Members of our Board of Directors are appointed to hold office until the next annual meeting of our stockholders or until his or her successor is elected and qualified, or until he or she resigns or is removed in accordance with the provisions of the Nevada Revised Statutes.

Director Compensation Table

The table below reflects compensation paid to non-employee directors for the year ended December 31, 2012.

Name	Fees Earned or Paid in Cash ($)
Alan W. Barksdale	13,000
Paul N. Vassilakos	14,000
John W. Hawkins	23,000
Richard F. LaRoche Jr	21,500
Randell K. Ford	11,500
Brad E. Heidelberg (1)	9,500

(1) Mr. Heidelberg received compensation pro rated for service from January 1, 2012 through the date of his resignation on May 8, 2012, in addition to cash fees for meetings in which Mr. Heidelberg participated.

Risk Management Relating to Compensation Policies

Due to the limited nature of compensation that we currently pay, particularly performance – based compensation, we do not believe there are any risks arising from our compensation policies and practices that are reasonably likely to have a material adverse effect on us.

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

The following table sets forth information regarding the beneficial ownership of our common stock as of April 1, 2013 by (i) each person known by us to be the beneficial owner of more than 5% of our outstanding shares of common stock; (ii) each of our Named Executive Officers and directors and (iii) all of our executive officers and directors as a group.

Name and Address of Beneficial Owner (1)	Amount of Beneficial Ownership (2)	Percentage of Outstanding Common Stock (2)
Alan W. Barksdale	16,542,945(3)	83.4%
Richard F. Laroche, Jr.	838,331(4)	5.1%
John W. Hawkins	10,000	*
Paul N. Vassilakos	—	—
Randell K. Ford	—	—
Earl M. Sebring	218,000	1.3%
Kenneth S. Lamb	—	—
All executive officers and directors as a group (7 persons)	17,609,276	6.4%
Red Mountain Resources, Inc. 2515 McKinney Ave, Suite 900 Dallas, TX 75201	16,542,945(3)	83..4%

* Less than one percent.

(1) Unless noted otherwise, the address for the above individuals is 2515 McKinney Ave., Suite 900, Dallas, Texas 75201. Unless noted otherwise, each of the above persons has sole voting and investment power with respect to all shares of common stock beneficially owned by them.

(2) Based on 16,301,946 shares of common stock issued and outstanding on December 31, 2012.

(3) Represents 14,040,114 shares of Common Stock held by Red Mountain. This also includes: (i) warrants to purchase 366,667 shares of Common Stock held by Red Mountain and (ii) warrants to purchase 2,136,164 shares of Common Stock held by Black Rock Capital, Inc., a wholly owned subsidiary of Red Mountain, all of which are immediately exercisable.

(4) Mr. LaRoche is deemed the beneficial owner of 838,331 Shares, or 5.1% of the Issuer's outstanding common stock, which ownership includes: (i) 94,984 Shares held by LaRoche Family, L.P., of which Mr. LaRoche is a general partner; (ii) 485,013 Shares held by LaRoche Enterprises, L.P., of which Mr. LaRoche is a general partner; (iii) 100,000 Shares held by Bushy Forest L.P.; of which Mr. LaRoche is a general partner; (iv) warrants to purchase 133,334 Shares held by LaRoche Enterprises, L.P, of which Mr. LaRoche is general partner; and (v) stock options to purchase 25,000 Shares held by Mr. LaRoche. As general partner of LaRoche Family, L.P., LaRoche Enterprises, L.P. and Bushy Forest, L.P., Mr. LaRoche has sole power to vote and to dispose of the Shares; accordingly, he is deemed to have beneficial ownership over such shares. However, Mr. LaRoche disclaims beneficial ownership of Shares held by the limited partnerships except to the extent of his pecuniary interest therein.

Equity Compensation Plans

Effective April 29, 2009, our Board of Directors adopted our 2009 Stock Incentive Plan (the "2009 Plan"). The purpose of the 2009 Plan is to enhance our long-term stockholder value by offering opportunities to our directors, officers, employees and eligible consultants ("Participants") to acquire and maintain stock ownership in us in order to give these persons the opportunity to participate in our growth and success, and to encourage them to remain in our service.

The 2009 Plan allows us to grant awards to our officers, directors and employees. In addition, we may grant awards to individuals who act as consultants to us, so long as those consultants do not provide services connected to the offer or sale of our securities in capital raising transactions and do not directly or indirectly promote or maintain a market for our securities.

On adoption, a total of 8,500,000 shares of our common stock were available for issuance under the 2009 Plan. Effective July 28, 2010, we amended and restated our 2009 Plan to increase the total number of shares authorized for issuance under the 2009 Plan to 14,500,000 shares. However, under the terms of the 2009 Plan, at any time after August 1, 2010, the authorized number of shares available under the 2009 Plan may be increased by our Board of Directors, provided that the total number of shares issuable under the 2009 Plan cannot exceed 15% of the total number of shares of common stock outstanding.

Awards may be granted in the form of options to purchase shares of our common stock ("Option Awards") or in the form of shares of our common stock ("Stock Awards"). Option Awards granted under the 2009 Plan may be made in the form of incentive stock options and non-qualified stock options. Incentive stock options granted under the 2009 Plan are those intended to qualify as "incentive stock options" as defined under Section 422 of the Internal Revenue Code. However, in order to qualify as "incentive stock options" under Section 422 of the Internal Revenue Code, the 2009 Plan must be approved by our stockholders within 12 months of its adoption. The 2009 Plan has not been approved by our stockholders and there is no assurance that the 2009 Plan will be approved by our stockholders. Non-qualified stock options granted under the 2009 Plan are Option Awards that do not qualify as incentive stock options under Section 422 of the Internal Revenue Code. Stock Awards may be made subject to such terms, conditions and restrictions as the plan administrator may, in its sole discretion, decide, including transfer restrictions and vesting provisions. On May 26, 2009, we filed a Registration Statement on Form S-8 (Registration Number 333-159480) under the Securities Act of 1933, as amended (the "Securities Act"), to register 8,500,000 shares of our common stock available for issuance under the 2009 Plan.

On August 10, 2010, we filed a Registration Statement on Form S-8 (Registration Number 333-168724) under the Securities Act to register an additional 6,000,000 shares of our common stock available for issuance under the 2009 Plan as amended and restated. The total registered shares available for issuance under the 2009 Plan was reduced to 263,636 shares by the 1-for-55 reverse split effective December 27, 2010. The 2009 Plan expressly provides that the number of shares may be increased to the number of shares issued under the 2009 Plan provided that it does not exceed 15% of the outstanding shares. The total number of shares underlying currently outstanding options issued under the Plan is 87,500.

The following table sets forth certain information concerning all equity compensation plans previously approved by stockholders and all previous equity compensation plans not previously approved by stockholders, as of the most recently completed fiscal year.

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants, and Rights (a)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in column (a)) (c)
Equity compensation plans approved by security holders	—	—	—
Equity compensation plans not approved by security holders	87,500	$ 4.80	2,357,792
Total	87,500	$ 4.80	2,357,792

(1) The total number of securities available for issuance under the plan cannot exceed 15% of the total number of shares of common stock outstanding. Therefore, as of April 1, 2013, the number of securities remaining available is 15% of 16,301,946 (2,445,292) less outstanding options (87,500).

Item 13. Certain Relationships and Related Transactions, and Director Independence

The Company paid $163,000 for consulting fees in the year ended December 31, 2011, respectively to BDR Consulting, Inc. (BDR), a member of CCJ/BDR Investments, L.L.C., who owned a combined 64.108% limited partnership interest in the Pure Gas Partners, L.P. The president of BDR also served on the Board of Directors and was the Chief Executive Officer of Pure Energy Group, Inc.

On April 11, 2012, the Company advanced its then Chief Executive Officer, E. Willard Gray, II, $119,575 related to the change in control provisions in Mr. Gray's employment agreement. At June 30, 2012, $42,070 remained outstanding (shown as Accounts receivable - related party on the Balance Sheet), which was deducted from the second change of control payment to him from the Company in July 2012.

During the year ended December 31, 2012, Red Mountain Resources, Inc. incurred approximately $628,274 for general and administrative expenses and operating costs that will be reimbursed by the Company for accounting services and attendance of certain of the Company’s directors and officers at the Company’s annual meeting of stockholders and for costs associated with workovers on three of the Company’s salt water disposal wells, of which

$215,495 remained unpaid at December 31, 2012. The expenditures pertaining to the operating costs were incurred pursuant to a technical services agreement between the Company and Red Mountain Resources, Inc.

The Company paid $720 and $91,633 for consulting fees and expense reimbursements for the years ended December 31, 2012 and 2011, respectively to Sebring Exploration Texas, Inc., an entity owned by Earl M. Sebring, the Company's Interim President.

In addition, the Company entered into various severance and release agreements with its former executive officers as described under Item 11. Executive Compensation under the heading "Employment Agreements."

As a matter of practice, the Board considers and approves or disapproves all transactions with related parties upon full disclosure of the relationship and potential conflict of interest. The Company has no written policy regarding related party transactions.

Independence of Directors

The standards relied upon the Board in determining whether a director is "independent" are those set forth in the rules of the NYSE MKT LLC (formerly, NYSE Amex). The NYSE MKT LLC generally defines "independent directors" as a person other than an executive officer or employee of a company, who does not have a relationship with the company that would interfere with the director's exercise of independent judgment in carrying out the responsibilities of a director. Consistent with these standards, our Board of Directors has affirmatively determined that Messrs. Hawkins, LaRoche, Vassilakos, and Ford are our independent directors.

Item 14. Principal Accountant Fees And Services

Aggregate fees for professional services provided to us by Darilek, Butler & Associates, PLLC, our principal accountant for the year ended December 31, 2012 were as follows:

	Year ended December 31,	
	2012	2011
Audit Fees(a)	$161,357	$103,100
Audit-Related Fees	—	8,475
Tax Fees(b)	9,775	11,487
All Other Fees	—	—
Total	$171,132	$123,062

(a) Audit services billed consisted of the audits of our annual consolidated financial statements, audits of internal control over financial reporting and reviews of our quarterly condensed consolidated financial statements.

(b) Tax fees include tax compliance and tax planning.

Audit Committee Approval

The Company's board of directors has adopted a procedure for pre-approval of all fees charged by its independent registered public accounting firm. Under the procedure, the audit committee of the Company's board of directors approves the engagement letter with respect to audit, tax and review services. Other fees are subject to pre-approval by the audit committee. The audit, audit-related fees and tax fees paid to Darilek Butler & Associates, PLLC with respect to 2012 were pre-approved by the audit committee.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) The following documents are filed as part of this Annual Report on Form 10-K:

1. Report of Independent Registered Public Accounting Firm
Balance Sheets as of December 31, 2012 and 2011
Statements of Operations for the Years Ended December 31, 2012 and 2011
Statements of Cash Flows for the Years Ended December 31, 2012 and 2011
Statements of Stockholders' Equity for the Years Ended December 31, 2012 and 2011
Notes to Financial Statements

2. Exhibits required to be filed by Item 601 of Regulation S-K

The exhibits required to be filed by this Item 15 are set forth in the Exhibit Index accompanying this report.

ROBERT F. DARILEK, C.P.A.
STEVEN H. BUTLER, C.P.A.

2702 N. Loop 1604 East, Ste. 202
San Antonio, Texas 78232
Phone (210) 979-0055
Fax (210) 979-0058

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and
Stockholders of Cross Border Resources, Inc.
San Antonio, Texas

We have audited the accompanying balance sheets of Cross Border Resources, Inc. (The Company) as of December 31, 2012 and 2011 and the related statements of operations, stockholders' equity and cash flows for the years then ended. The Company's management is responsible for these financial statements. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Note: this follows 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 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 the Company as of December 31, 2012 and 2011, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

The accompanying financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 1 to the financial statements, the Company's significant operating losses and negative working capital raise substantial doubt about its ability to continue as a going concern. The financial statements do not include any adjustments that might result from the outcome of this uncertainty. Our opinion is not modified with respect to that matter.

/s/DARILEK BUTLER & ASSOCIATES, PLLC

San Antonio, Texas
March 29, 2013

A Limited Liability Company • Members AICPA PCPS and TSCPA

Cross Border Resources, Inc.
Balance Sheets

	December 31, 2012	December 31, 2011
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 241,561	$ 472,967
Accounts Receivable – Oil and Natural Gas Sales	3,194,725	1,184,544
Prepaid Expenses & Other Current Assets	465,223	1,808,944
Derivative Asset - Current Portion	235,825	—
Current Tax Asset	21,737	21,737
Total Current Assets	4,159,071	3,488,192
Oil and Gas Properties	48,248,378	34,986,566
Less: Accumulated Depletion, Amortization, and Impairment	(16,018,892)	(9,667,031)
Net Oil and Gas Properties	32,229,486	25,319,535
Other Assets		
Other Property and Equipment, net of Accumulated Depreciation of $77,190 and $126,473 in 2012 and 2011, respectively	53,280	95,988
Deferred Bond Costs, net of Accumulated Amortization of $503,854 and $344,300 in 2012 and 2011, respectively	—	159,554
Deferred Bond Discount, net of Accumulated Amortization of $186,560 and $127,483 in 2012 and 2011, respectively	—	59,077
Deferred financing costs, net of accumulated amortization of $113,581 and $26,355 in 2012 and 2011, respectively	101,045	64,746
Derivative Asset, net of Current Portion	54,963	—
Other Assets	54,324	54,324
Total Other Assets	263,612	433,689
TOTAL ASSETS	$ 36,652,169	$ 29,241,416

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

	December 31, 2012	December 31, 2011
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable - Trade	$ 4,226,547	$ 1,177,383
Accounts Payable – Related Party	215,495	—
Interest Payable – Related Party	130,929	—
Notes Payable	—	764,278
Accrued Expenses & Other Payables	61,065	627,810
Deferred Revenues	—	32,479
Notes Payable – Related Party - Current	764,278	—
Interest Payable	—	112,659
Bonds Payable - Current Portion	—	570,000
Creditors Payable - Current Portion	758,167	186,761
Environmental Liability – Current Portion	860,000	—
Asset Retirement Obligation – Current Portion	452,013	—
Deferred Tax Liability	21,737	—
Derivative Liability - Current Portion	—	56,908
Total Current Liabilities	7,490,231	3,528,278
Non-Current Liabilities		
Asset Retirement Obligations	2,865,345	1,186,260
Deferred Income Tax Liability	—	21,737
Environmental Liability	1,240,000	—
Line of Credit	8,750,000	2,381,000
Derivative Liability, net of Current Portion	—	28,086
Bonds Payable, net of Current Portion	—	2,825,000
Creditors Payable, net of Current Portion	594,616	1,352,783
Total Non-Current Liabilities	13,449,961	7,794,866
Total Liabilities	20,940,192	11,323,144
Commitments & Contingencies (Note 10)		
Stockholders' Equity		
Common Stock ($0.001 par value; 99,000,000 shares authorized and 16,301,946 issued and outstanding as of December 31, 2012 and 16,151,946 as of December 31, 2011)	16,302	16,152
Additional Paid in Capital	32,770,540	32,617,690
Accumulated Deficit	(17,074,865)	(14,715,570)
Total Stockholders' Equity	15,711,977	17,918,272
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 36,652,169	$ 29,241,416

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

Cross Border Resources, Inc.

Statements of Operations

	December 31, 2012	December 31, 2011
Revenues		
Oil and gas sales	$ 14,781,497	$ 6,584,134
Other	—	129,915
Total revenues	14,781,497	6,714,049
Expenses:		
Operating costs	2,281,443	1,434,678
Environmental cleanup	2,100,000	—
Natural gas marketing and transportation expenses	143,672	10,301
Impairment expense	2,633,742	49,234
Production taxes	1,171,474	555,698
Depreciation, depletion, and amortization	5,671,202	2,105,851
Gain on sale of oil and gas properties	—	(599,100)
Accretion expense	94,556	84,428
General and administrative	2,851,003	3,664,355
Total expense	16,947,092	7,305,445
Loss from operations	(2,165,595)	(591,396)
Other income (expense):		
Bond issuance amortization	(218,631)	(50,385)
Gain (loss) on derivatives	575,086	(11,771)
Interest expense	(547,066)	(460,275)
Miscellaneous other income	(3,089)	252,497