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

FORM 10-K

[X] Annual report under Section 13 or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2013.

[ ] Transition report under Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from ___________ to ___________

Commission File Number: 001-32624

FIELDPOINT PETROLEUM CORPORATION

(Name of Small Business Issuer in Its Charter)

Colorado	**84-0811034**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

609 Castle Ridge Road, Suite 335
Austin, Texas 78746
(Address of Principal Executive Offices) (Zip Code)

(512) 579-3560
(Issuer's Telephone Number, Including Area Code)

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

Securities registered under Section 12(g) of the Exchange Act:

Common Stock, $.01 Par Value
Title of Class

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. [____]

Note – Checking the box above will not relieve any registrant required to file reports pursuant to Section 13 or 15(d) of the Exchange Act from their obligations under those Sections.

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

Indicate by check mark 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. [X]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, 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 [ ]

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

Large accelerated filer [___] Accelerated filer [__]

Non-accelerated filer [___] (Do not check if a smaller reporting company) Smaller reporting company [_X_]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes____ No_X__

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was sold, or the average bid and asked price of such common equity, as of June 30, 2013, was $17,859,293.

The number of shares outstanding of the registrant's common stock as of March 27, 2014 is 8,069,236.

List hereunder the following documents if incorporated by reference and the Part of the Form 10-K (*e.g.*, Part I, Part II, etc.) into which the document is incorporated: (1) Any annual report to security holders; (2) Any proxy or information statement; and (3) Any prospectus filed pursuant to Rule 424(b) or (c) under the Securities Act of 1933. The listed documents should be clearly described for identification purposes

Exhibits

See Part IV, Item 15.

PART I

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in this Form 10-K constitute “forward-looking statements’ within the meaning of the Private Securities Litigation Reform Act and Section 27A of the Securities Exchange Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, included in this Form 10-K that address activities, events or developments that FieldPoint Petroleum Corp. and its subsidiaries (collectively, the "Company", “we”, “us”, “our” or “ours”) expects, projects, believes or anticipates will or may occur in the future, including such matters as oil and natural gas reserves, future drilling and operations, future production of oil and natural gas, future net cash flows, future capital expenditures and other such matters, are forward-looking statements. Such forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such factors include, among others, the following: the volatility of oil and natural gas prices, the Company’s drilling and acquisition results, the Company’s ability to replace reserves, the availability of capital resources, the reliance upon estimates of proved reserves, operating hazards and uninsured risks, competition, government regulation, the ability of the Company to implement its business strategy and other factors referenced in this Form 10-K.

ITEM 1- BUSINESS

General

FieldPoint Petroleum Corporation, a Colorado corporation (the “Company”), was formed on March 11, 1980, to acquire and enhance mature oil and natural gas field production in the mid-continent and the Rocky Mountain regions. Since 1980, the Company had engaged in oil and natural gas operations and, in 1986, divested all oil and natural gas assets and operations. From December 1986, until its reverse acquisition on December 31, 1997, the Company did not engage in oil and natural gas operations. Since the reverse acquisition on December 31, 1997 the Company has been in the oil and natural gas exploration and production business.

Business Strategy

The Company’s business strategy is to continue to expand its reserve base and increase production and cash flow through the acquisition of producing oil and natural gas properties. Such acquisitions will be based on an analysis of the properties' current cash flow and the Company's ability to profit from the acquisition. The Company's ideal acquisition will include not only oil and natural gas production, but also leasehold and other working interests in exploration areas.

The Company will also seek to identify promising areas for the exploration of oil and natural gas through the use of outside consultants and the expertise of the Company. This identification will include collecting and analyzing geological and geophysical data for exploration areas. Once promising properties are identified, the Company will attempt to acquire the properties either for drilling oil and natural gas wells, using independent contractors for drilling operations, or for sale to third parties.

The Company recognizes that the ability to implement its business strategies is largely dependent on the ability to raise additional debt or equity capital to fund future acquisition, exploration, drilling and development activities. The Company's capital resources are discussed more thoroughly in Part II, Item 7, in Management's Discussion and Analysis.

Operations

As of December 31, 2013, the Company had varying ownership interest in 360 gross wells (100.71 net) located in five states. The Company operates 65 of the 360 wells; the other wells are operated by independent operators under contracts that are standard in the industry. It is a primary objective of the Company to operate some of the oil and natural gas properties in which it has an economic interest, and the Company will also partner with larger oil and natural gas companies to operate certain oil and natural gas properties in which the Company has an economic interest. The Company believes, with the responsibility and authority as operator, it is in a better position to control cost, safety, and timeliness of work as well as other critical factors affecting the economics of a well.

Market for Oil and Natural Gas

The demand for oil and natural gas is dependent upon a number of factors, including the availability of other domestic production, crude oil imports, the proximity and size of oil and natural gas pipelines in general, other transportation facilities, the marketing of competitive fuels, and general fluctuations in the supply and demand for oil and natural gas. The Company intends to sell all of its production to traditional industry purchasers, such as pipeline and crude oil companies, who have facilities to transport the oil and natural gas from the well site.

Competition

The oil and natural gas industry is highly competitive in all aspects. The Company competes with major oil companies, numerous independent oil and natural gas producers, individual proprietors, and investment programs. Many of these competitors possess financial and personnel resources substantially in excess of those which are available to the Company and may, therefore, be able to pay greater amounts for desirable leases and define, evaluate, bid for and purchase a greater number of potential producing prospects that the Company's own resources permit. The Company's ability to generate resources will depend not only on its ability to develop existing properties but also on its ability to identify and acquire proven and unproven acreage and prospects for further exploration.

Hydraulic Fracturing

Hydraulic fracturing is an important process and has been commonly used in the completion of unconventional oil and gas wells in shale and tight sand formations since the 1950s. Hydraulic fracturing involves the injection of water, sand and chemical additives under pressure into rock formations to stimulate oil and gas production. It is important to us because it provides access to oil and gas reserves that previously were uneconomical to produce.

We currently use hydraulic fracturing to complete both horizontal and vertical wells in the Permian Basin. We engage third parties to provide hydraulic fracturing services to us for completion of these wells. While hydraulic fracturing is not required to maintain our leasehold acreage that is currently held by production from existing wells, it will be required in the future to develop the proved non-producing and proved undeveloped reserves associated with this acreage. All of our proved non-producing and proved undeveloped reserves associated with future drilling, completion and recompletion projects will require hydraulic fracturing.

We believe we have followed, and intend to continue to follow, applicable industry standard practices and legal requirements for groundwater protection in our operations that are subject to supervision by state regulators.

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 well to create a permanent isolating barrier between the casing pipe and surrounding geological formations. This aspect of well design is intended to prevent contact between the fracturing fluid and any aquifers during the hydraulic fracturing operations. For recompletions of existing wells, the production casing is pressure-tested before 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. We believe we have adequate procedures in place to address abrupt changes to the injection pressure or annular pressure.

Texas regulations currently require disclosure of the components in the solutions used in hydraulic fracturing operations. Over 99% (by mass) of the ingredients we use in hydraulic fracturing are water and sand. The remainder of the ingredients are chemical additives that are managed and used in accordance with applicable requirements.

Hydraulic fracturing requires the use of a significant amount of water. Upon flowback of the water, we dispose of it in a way that we believe minimizes the impact to nearby surface water by disposing into approved disposal facilities or injection wells. Currently our primary sources of water are nonpotable and potable aquifers. We use water from on-lease water wells that we have drilled, and we purchase water from off-lease water wells. We also plan to reuse and recycle flow-back and produced water in 2014.

Operational Hazards and Insurance

The Company's operations are subject to the usual hazards incident to the drilling and production of oil and natural gas, such as blowouts, cratering, explosions, uncontrollable flows of oil, natural gas or well fluids, fires, pollution, releases of toxic gas and other environmental hazards and risks. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations.

The Company maintains insurance of various types to cover its operations. The Company's insurance does not cover every potential risk associated with the drilling and production of oil and natural gas. In particular, coverage is not obtainable for certain types of environmental hazards. The occurrence of a significant adverse event, the risks of which are not fully covered by insurance, could have a material adverse effect on the Company's financial condition and results of operations. Moreover, no assurance can be given that the Company will be able to maintain adequate insurance in the future at rates it considers reasonable.

Regulation

The oil and gas industry in the United States is subject to extensive regulation by federal, state and local authorities. At the federal level, various federal rules, regulations and procedures apply, including those issued by the U.S. Department of Interior, the U.S. Department of Transportation (the “DOT”) (Office of Pipeline Safety) and the U.S. Environmental Protection Agency (the “EPA”). At the state and local level, various agencies and commissions regulate drilling, production and midstream activities. These federal, state and local authorities have various permitting, licensing and bonding requirements. Various remedies are available for enforcement of these federal, state and local rules, regulations and procedures, including fines, penalties, revocation of permits and licenses, actions affecting the value of leases, wells or other assets, and suspension of production. As a result, there can be no assurance that we will not incur liability for fines, penalties or other remedies that are available to these federal, state and local authorities. However, we believe that we are currently in material compliance with federal, state and local rules, regulations and procedures, and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations.

Transportation and Sale of Oil

Sales of crude oil and condensate are not currently regulated and are made at negotiated prices. Our sales of crude oil are affected by the availability, terms and cost of transportation. Interstate transportation of oil by pipeline is regulated by the Federal Energy Regulation Commission (“FERC”) pursuant to the Interstate Commerce Act (“ICA”), Energy Policy Act of 1992 (“EPAct 1992”), and the rules and regulations promulgated under those laws. The ICA and its regulations require that tariff rates for interstate service on oil pipelines, including interstate pipelines that transport crude oil and refined products, be just and reasonable and non-discriminatory and that such rates, terms and conditions of service be filed with FERC.

Intrastate oil pipeline transportation rates are also 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 oil pipelines operate at 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.

The transportation of oil by truck is also subject to federal, state and local rules and regulations, including the Federal Motor Carrier Safety Act and the Homeland Security Act of 2002. Regulations under these statutes cover the security and transportation of hazardous materials and are administered by the DOT.

Transportation and Sale of Natural Gas and NGLs

FERC regulates interstate gas pipeline transportation rates and service conditions under the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and regulations issued under those statutes. FERC also regulates interstate NGL pipelines under various federal laws and regulations. Although FERC does not regulate oil and gas producers such as us, FERC’s actions are intended to facilitate increased competition within all phases of the oil and gas industry and its regulation of third-party pipelines and facilities could indirectly affect our ability to transport or market our production. To date, FERC's policies have not materially affected our business or operations.

Regulation of Production

Oil, NGL and gas production is regulated under a wide range of federal and state statutes, rules, orders and regulations. State and federal statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. The state in which we operate, have regulations governing conservation matters, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum rates of production from oil and gas wells, the regulation of spacing, and requirements for plugging and abandonment of wells. Also, some states, including Texas imposes a severance tax on production and sales of oil, NGLs and gas within its jurisdiction. The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Environmental Laws and Regulations

In the United States, the exploration for and development of oil and gas and the drilling and operation of wells, fields and gathering systems are subject to extensive federal, state and local laws and regulations governing environmental protection as well as discharge of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling begins;

- require the installation of expensive pollution controls or emissions monitoring equipment;

- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and gas drilling, completion, production, transportation and processing activities;

- suspend, limit or prohibit construction, drilling and other activities in certain lands lying within wilderness, wetlands, endangered species habitat, and other protected areas; and

- require remedial measures to mitigate and remediate pollution from historical and ongoing operations, such as the closure of waste pits and plugging of abandoned wells.

These laws, rules and regulations may also restrict the rate of oil and gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability.

Governmental authorities have the power to enforce compliance with environmental laws, regulations and permits, and violations are subject to injunction, as well as administrative, civil and criminal penalties. The effects of existing and future laws and regulations could have a material adverse impact on our business, financial condition and results of operations. The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. Any changes in environmental laws and regulations or re-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 business, financial condition or results of operations. Moreover, accidental releases or spills and ground water contamination may occur in the course of our operations, and we may incur significant costs and liabilities as a result of such releases, spills or contamination, including any third-party claims for damage to property, natural resources or persons. We maintain insurance against costs of clean-up operations, but we are not fully insured against all such risks. While we believe that we are in substantial compliance with existing environmental laws and regulations and that continued compliance with current requirements would not have a material adverse effect on us, there is no assurance that this will continue in the future.

The following is a summary of some of the existing environmental laws, rules and regulations that apply to our business operations.

Hazardous Substance Release

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA"), also known as the Superfund law, and comparable state statutes impose strict liability, and under certain circumstances, joint and several liability, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to strict, joint and several liabilities for the costs of investigating releases of hazardous substances, cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third-parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. While we generate materials in the course of our operations that may be regulated as hazardous substances, we have not received notification that we may be potentially responsible for cleanup costs under CERCLA.

Waste Handling

The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced water and most of the other wastes associated with the exploration, development and production of oil or gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could increase our operating expenses, which could have a material adverse effect on our business, financial condition and results of operations.

We currently own or lease properties that for many years have been used for oil and gas exploration, production and development activities. Although we used operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed of or released on, under or from the properties owned or leased by us or on, under or from other locations where such wastes have been taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons and wastes was not under our control. These properties and the materials disposed or released on, at, under or from them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes or contamination, or to perform remedial activities to prevent future contamination.

Air Emissions

The federal Clean Air Act and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions at specified sources. In particular, on April 18, 2012, the EPA issued new regulations under the New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAP"). The new regulations are designed to reduce volatile organic compound ("VOC") emissions from hydraulically-fractured natural gas wells, storage tanks and other equipment. The regulations established a phase-in period that extends until January 2015. During the phase-in period, owners and operators of hydraulically-fractured natural gas wells (wells drilled principally for the production of natural gas) must either flare their emissions or use so-called "green completion" technology. Green completions allow for the recovery of natural gas that formerly would have been vented or flared. Beginning January 1, 2015, all newly fractured natural gas wells must use green completion technology. We do not expect that the NSPS or NESHAP will have a material adverse effect on our business, financial condition or results of operations. However, any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements or use specific equipment or technologies to control emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions. We believe that we currently are in substantial compliance with all air emissions regulations and that we hold all necessary and valid construction and operating permits for our current operations.

Greenhouse Gas Emissions

Congress has, from time-to-time, considered legislation to reduce emissions of GHGs. The current Congress is likely to continue to consider similar bills. Moreover, almost half of the states have already taken legal measures to reduce emissions of GHGs through the planned development of GHG emission inventories and/or regional GHG cap-and-trade programs or other mechanisms. Most cap-and-trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels such as refineries and gas processing plants, to acquire and surrender emission allowances corresponding with their annual emissions of GHGs. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. Many states have enacted renewable portfolio standards, which require utilities to purchase a certain percentage of their energy from renewable fuel sources.

In response to the findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act. The EPA has adopted two sets of rules regarding possible future regulation of GHG emissions under the Clean Air Act, one of which purports to regulate emissions of GHGs from motor vehicles and the other of which would regulate emissions of GHGs from large stationary sources of emissions such as power plants or industrial facilities. The motor vehicle rule was finalized in April 2010 and became effective in January 2011, but it does not require immediate reductions in GHG emissions. In March 2012, the EPA proposed GHG emissions standards for fossil fuel-powered electric utility generating units that would require new plants to meet an output-based standard of 1,000 pounds of carbon dioxide equivalent per megawatt-hour. If the proposed regulation is adopted, it could have a significant impact on the electrical generation industry and may favor the use of natural gas over other fossil fuels such as coal in new plants. The EPA has also indicated that it will propose new GHG emissions standards for refineries, but specific proposed regulations are not expected to be issued until mid-2013.

In December 2010, the EPA enacted final rules on mandatory reporting of GHGs. In 2011, the EPA published amendments to the rule containing technical and clarifying changes to certain GHG reporting requirements and a six-month extension for reporting GHG emissions from petroleum and natural gas industry sources. Under the amended rule, certain onshore oil and natural gas production, processing, transmission, storage and distribution facilities are required to report their GHG emissions on an annual basis. We do not expect that the EPA's mandatory GHG reporting requirements will have a material adverse effect on our business, financial condition or results of operations.

The adoption of additional legislation or regulatory programs to monitor or reduce GHG emissions could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, acquire emissions allowances or comply with new regulatory requirements. In addition, the EPA has stated that the data collected from GHG emissions reporting programs may be the basis for future regulatory action to establish substantive GHG emissions factors. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have an adverse effect on our future business, financial condition and results of operations.

Water Discharges

The Federal Water Pollution Control Act (the "Clean Water Act") and analogous state laws, impose restrictions and strict controls on the discharge of pollutants and fill material, including spills and leaks of oil and other substances into regulated waters, including wetlands. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA, an analogous state agency, or, in the case of fill material, the United States Army Corps of Engineers. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

In October 2011, the EPA announced that it intends to develop national standards for wastewater discharges produced by natural gas extraction from shale and coalbed methane formations. The EPA is expected to issue proposed regulations establishing wastewater discharge standards for coalbed methane wastewater in 2013 and for shale gas wastewater in 2014. For shale gas wastewater, the EPA will consider imposing pre-treatment standards for discharges to a wastewater treatment facility. Produced and other flowback water from our current operations is typically re-injected into underground formations that do not contain potable water. To the extent that re-injection is not available for our operations and discharge to wastewater treatment facilities is required, new standards from the EPA could increase the cost of disposing wastewater in connection with our operations.

The Safe Drinking Water Act, Groundwater Protection and the Underground Injection Control Program

The federal Safe Drinking Water Act ("SDWA") and the Underground Injection Control program (the "UIC program") promulgated under the SDWA and state programs regulate the drilling and operation of salt water disposal wells. The EPA has delegated administration of the UIC program in Texas to the Railroad Commission of Texas ("RRC"). Permits must be obtained before drilling salt water disposal wells, and casing integrity monitoring must be conducted periodically to ensure the casing is not leaking saltwater to groundwater. Contamination of groundwater by oil and gas drilling, production and related operations may result in fines, penalties and remediation costs, among other sanctions and liabilities under the SDWA and state laws. In addition, third-party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages and bodily injury.

Hydraulic Fracturing

Hydraulic fracturing is the subject of significant focus among some environmentalists, regulators and the general public. Concerns over potential hazards associated with the use of hydraulic fracturing and its impact on the environment have been raised at all levels, including federal, state and local, as well as internationally. There have been claims that hydraulic fracturing may contaminate groundwater, reduce air quality or cause earthquakes. Hydraulic fracturing requires the use and disposal of water, and public concern has been growing over its possible effects on drinking water supplies, as well as the adequacy of water supply.

The Energy Policy Act of 2005, which exempts hydraulic fracturing from regulation under the SDWA, prohibits the use of diesel fuel in the fracturing process without a UIC permit. In the past, legislation has been introduced in, but not passed by, Congress that would amend the SDWA to repeal this exemption. Specifically, the FRAC Act has been introduced in each Congress since 2008 to accomplish these purposes, and on May 9, 2013, the FRAC Act was again introduced. If similar legislation were enacted, it could require hydraulic fracturing operations to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting and recordkeeping obligations and meet plugging and abandonment requirements. Future federal legislation could also require the reporting and public disclosure of chemical additives used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemical additives used in the fracturing process could adversely affect groundwater. If federal legislation regulating hydraulic fracturing is adopted in the future, it could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

In 2010, the EPA asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the UIC program by posting a requirement on its website that requires facilities to obtain permits to use diesel fuel in hydraulic fracturing operations. Industry groups filed suit challenging the EPA's decision as a "final agency action" and, therefore, a violation of the notice-and-comment rulemaking procedures of the Administrative Procedures Act. In February 2012, the EPA and industry reached a settlement under which the EPA will modify the informal policy posted on its website concerning the need for permits under the UIC program. However, the settlement does not reflect agreement on the issue of hydraulic fracturing regulation under the SDWA, and the EPA's continued assertion of its regulatory authority under the SDWA could result in extensive requirements that could cause additional costs and delays in the hydraulic fracturing process.

In addition to the above actions of the EPA, certain members of the Congress have called upon (i) the Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources; (ii) the Securities and Exchange Commission (the "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 shale by means of hydraulic fracturing; and (iii) the 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. The SEC has issued subpoenas to certain shale gas producers requesting information on proved reserve estimates from shale gas wells and the actual productivity of producing shale gas wells. The media has also reported that the New York attorney general has issued subpoenas to certain oil and gas companies seeking information regarding shale gas wells.

There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has also begun a study of the potential environmental impacts of hydraulic fracturing. The EPA issued a progress report in December 2012, and final results are expected in 2014. In addition, the U.S. Department of Energy conducted an investigation into practices the agency could recommend to better protect the environment from using hydraulic fracturing. The Shale Gas Subcommittee of the Secretary of Energy Advisory Board released its "90-day" report on August 18, 2011, and its final report on November 18, 2011, proposing recommendations to reduce the potential environmental impacts from shale gas production. Also, the U.S. Department of the Interior published a revised proposed rule in May 2013 that would implement updated requirements for hydraulic fracturing activities on federal lands, including new requirements relating to public disclosure, well bore integrity and handling of flowback water. Other governmental agencies, including the US Department of Energy, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed investigations and studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing.

Some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances or otherwise require the public disclosure of chemicals used in hydraulic fracturing. For example, pursuant to legislation adopted by the State of Texas in June 2011, the RRC enacted a rule in December 2011, requiring disclosure to the RRC and the public of certain information regarding additives, chemical ingredients, concentrations and water volumes used in hydraulic fracturing. In addition to state law, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general and hydraulic fracturing in particular.

If these or any other new laws or regulations that significantly restrict hydraulic fracturing are adopted, it could become more difficult or costly for us to drill and produce oil and gas from shale and tight sands formations and become easier for third parties opposing hydraulic fracturing to initiate legal proceedings. In addition, if hydraulic fracturing is regulated at the federal level, fracturing activities could become subject to delays, additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and higher costs. These new laws or regulations could cause us to incur substantial delays or suspensions of operations and compliance costs and could have a material adverse effect on our business, financial condition and results of operations.

Compliance

We believe that we are in substantial compliance with all existing environmental laws and regulations that apply to our current operations and that our ongoing compliance with existing requirements will not have a material adverse effect on our business, financial condition or results of operations. We did not incur any material capital expenditures for remediation or pollution control activities for the year ended December 31, 2013. In addition, as of the date of this report, we are not aware of any environmental issues or claims that will require material capital or operating expenditures during 2014. However, the passage of additional or more stringent laws or regulations in the future could have a negative effect on our business, financial condition and results of operations, including our ability to develop our undeveloped acreage.

Threatened and Endangered Species, Migratory Birds and Natural Resources

Various state and federal statutes prohibit certain actions that adversely affect endangered or threatened species and their habitat, migratory birds, wetlands and natural resources. These statutes include the Endangered Species Act, the Migratory Bird Treaty Act, the Clean Water Act and CERCLA. The United States Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for survival of threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and private land use and could delay or prohibit land access or development. Where takings of, or harm to, species or damages to wetlands, habitat or natural resources occur or may occur, government entities or at times private parties may act to prevent oil and gas exploration activities or seek damages for harm to species, habitat or natural resources resulting from drilling or construction or releases of oil, wastes, hazardous substances or other regulated materials, and may seek natural resources damages and, in some cases, criminal penalties.

OSHA and Other Laws and Regulations

We are subject to the requirements of the federal Occupational Safety and Health Act (“OSHA”) and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in substantial compliance with these applicable requirements and with other OSHA and comparable requirements.

Administration

Office Facilities – The office space for the Company's executive office is located at 609 Castle Ridge Road, Suite 335, Austin, Texas 78746.

Employees – As of March 27, 2014, the Company had 4 employees, and the Company considers its relationship with its employees satisfactory.

ITEM 1A – RISK FACTORS.

Oil and gas operations are risky.

We compete in the areas of oil and gas exploration, production, development and transportation with other companies, many of which may have substantially larger financial and other resources. The nature of the oil and gas business also involves a variety of risks, including the risks of operating hazards such as fires, explosions, cratering, blow-outs, and encountering formations with abnormal pressures, the occurrence of any of which could result in losses to us. We maintain insurance against some, but not all, of these risks in amounts that management believes to be reasonable in accordance with customary industry practices. The occurrence of a significant event, however, that is not fully insured could have a material adverse effect on our financial position.

A substantial decrease in oil and natural gas prices would have a material impact on us.

Our future financial condition and results of operations are dependent upon the prices we receive for our oil and natural gas production. Oil and natural gas prices historically have been volatile and likely will continue to be volatile in the future. This price volatility will also affect our common stock price. We cannot predict oil and natural gas prices and prices may decline in the future. The following factors have an influence on oil and natural gas prices, including but not limited to:

* changes in the supply of and demand for oil and natural gas;
* storage availability;
* weather conditions;
* market uncertainty;
* domestic and foreign governmental regulations;
* the availability and cost of alternative fuel sources;
* the domestic and foreign supply of oil and natural gas;
* the price of foreign oil and natural gas;
* refining capacity;
* political conditions in oil and natural gas producing regions, including the Middle East; and
* overall economic conditions.

To counter this volatility we, from time to time, may enter into agreements to receive fixed prices on our oil and gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, we would not benefit from such increases.

Our business will depend on transportation facilities owned by others.

The marketability of our gas production will depend in part on the availability, proximity, and capacity of pipeline systems owned by third parties. Although we will have some contractual control over the transportation of our product, material changes in these business relationships could materially affect our operations. Federal and state regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand and general economic conditions could adversely affect our ability to produce, gather, and transport oil and natural gas.

Market conditions could cause us to incur losses on our transportation contracts.

Gas transportation contracts that we may enter into in the future may require us to transport minimum volumes of natural gas. If we ship smaller volumes, we may be liable for the shortfall. Unforeseen events, including production problems or substantial decreases in the price of natural gas, could cause us to ship less than the required volumes, resulting in losses on these contracts.

Our actual production, revenues and expenditures related to our reserves are likely to differ from our estimates of our proved reserves. We may experience production that is less than estimated and drilling costs that are greater than estimated in our reserve reports. These differences may be material.

The proved oil, NGL and gas reserves data included in this report are estimates. Petroleum engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. Estimates of economically recoverable oil, NGL and gas reserves and of future net cash flows necessarily depend upon a number of variable factors and assumptions, including:

- historical production from the area compared with production from other similar producing areas;
- the assumed effects of regulations by governmental agencies;
- assumptions concerning future oil, NGL and gas prices; and
- assumptions concerning future operating costs, severance and excise taxes, development costs and workover and remedial costs.

Because all reserves estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating proved reserves:

- the quantities of oil, NGL and gas that are ultimately recovered;
- the production and operating costs incurred;
- the amount and timing of future development expenditures; and
- future oil, NGL and gas prices.

Estimates of proved undeveloped reserves are even less reliable than estimates of proved developed reserves. Furthermore, different reserve engineers may make different estimates of reserves and future net revenues based on the same available data. Our actual production, revenues and expenditures with respect to reserves will likely be different from estimates and the differences may be material.

Estimating our reserves future net cash flows is difficult to do with any certainty.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and their values, including many factors beyond our control. The reserve data included in this report represents only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data, the precision of the engineering and geological interpretation, and judgment. As a result, estimates of different engineers often vary. The estimates of reserves, future cash flows, and present value are based on various assumptions, including those prescribed by the Securities and Exchange Commission, and are inherently imprecise. There is no assurance that our present oil and gas wells will continue to produce at current or anticipated rates of production, or that production rates achieved in early periods can be maintained. Actual future production, cash flows, taxes, operating expenses, and quantities of recoverable oil and natural gas reserves may vary substantially from our estimates. Also, the use of a 10% discount factor for reporting purposes may not necessarily represent the most appropriate discount factor, given actual interest rates and risks to which our business or the oil and natural gas industry in general are subject.

Quantities of proved reserves are estimated based on economic conditions, including oil and natural gas prices in existence at the date of assessment. A reduction in oil and natural gas prices not only would reduce the value of any proved reserves, but also might reduce the amount of oil and natural gas that could be economically produced, thereby reducing the quantity of reserves. Our reserves and future cash flows may be subject to revisions, based upon changes in economic conditions, including oil and natural gas prices, as well as due to production results, operating costs, and other factors. Downward revisions of our reserves could have an adverse effect on our financial condition and operating results.

Acquiring interests in other properties involves substantial risks.

We evaluate and acquire interests in oil and natural gas properties which in management's judgment will provide attractive investment opportunities for the addition of production and oil and gas reserves. To acquire producing properties or undeveloped exploratory acreage will require an assessment of a number of factors including:

* Value of the properties and likelihood of future production;
* Recoverable reserves;
* Operating costs;
* Potential environmental and other liabilities;
* Drilling and production difficulties; and
* Other factors beyond our control

Such assessments will necessarily be inexact and uncertain. Because of our limited financial resources, we may not be able to evaluate properties in a manner that is consistent with industry practices. Such reviews, therefore, may not reveal all existing or potential problems, nor will they permit us to become sufficiently familiar with such properties to assess fully the deficiencies or benefits.

Operational risks in our business are numerous and could materially impact us.

Oil and natural gas drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be encountered. We can make no assurance that wells in which we have an interest will be productive or that we will recover all or any portion of investment costs.

Our operations are also subject to hazards and risks inherent in drilling for and producing and transporting oil and natural gas, including, but not limited to, such hazards as:

* Fires;
* Explosions;
* Blowouts;
* Encountering formations with abnormal pressures;
* Spills
* Natural disasters;
* Pipeline ruptures;
* Cratering

If any of these events occur in our operations, we could experience substantial losses due to:

* injury or loss of life;
* severe damage to or destruction of property, natural resources and equipment;
* pollution or other environmental damage;
* clean-up responsibilities;
* regulatory investigation and penalties; and
* other losses resulting in suspension of our operations.

In accordance with customary industry practice, we maintain insurance against some, but not all, of the risks described above with a general liability limit of $1 million. We do not maintain insurance for damages arising out of exposure to radioactive material. Even in the case of risks against which we are insured, our policies are subject to limitations and exceptions that could cause us to be unprotected against some or all of the risk. The occurrence of an uninsured loss could have a material adverse effect on our financial condition or results of operations.

We must comply with environmental regulations.

Exploratory and other oil and natural gas wells must be operated in compliance with complex and changing environmental laws and regulations adopted by federal, state and local government authorities. The implementation of new, or the modification of existing, laws and regulations could have a material adverse effect on properties in which we may have an interest. Discharge of oil, natural gas, water, or other pollutants to the oil, soil, or water may give rise to significant liabilities to government and third parties and may require us to incur substantial cost of remediation. We may be required to agree to indemnify sellers of properties purchased against certain liabilities for environmental claims associated with those properties. We can give no assurance that existing environmental laws or regulations, as currently interpreted, or as they may be reinterpreted in the future, or future laws or regulations will not materially adversely affect our results of operations and financial conditions.

Environmental liabilities could adversely affect our business

In the event of a release of oil, natural gas, or other pollutants from our operations into the environment, we could incur liability for personal injuries, property damage, cleanup costs, and governmental fines.

We could potentially discharge these materials into the environment in any of the following ways:

* from a well or drilling equipment at a drill site;
* leakage from gathering systems, pipelines, transportation facilities and storage tanks;
* damage to oil and natural gas wells resulting from accidents during normal operations; and
* blowouts, cratering, and explosions.

In addition, because we may acquire interests in properties that have been operated in the past by others, we may be liable for environmental damage, including historical contamination, caused by such former operators. Additional liabilities could also arise from continuing violations or contamination not discovered during our assessment of the acquired properties.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays in our production of oil and gas and lower returns on our capital investments.

Bills were introduced in the previous U.S. Congress to regulate hydraulic fracturing operations and related injection of fracturing fluids and propping agents used in fracturing fluids by the oil and natural gas industry under the federal Safe Drinking Water Act ("SDWA") and to require the disclosure of chemicals used in the hydraulic fracturing process under the SDWA, Emergency Planning and Community Right-to-Know Act ("EPCRA") or other authority. Hydraulic fracturing is an important and commonly used process in the completion of unconventional oil and natural gas wells in shale and tight sand formations. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate oil and natural gas production. We engage third parties to provide hydraulic fracturing or other well stimulation services to us for many of the wells that we drill and operate. Sponsors of such bills have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies, surface waters, and other natural resources, and threaten health and safety. In addition, the EPA has announced its intention to conduct a comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on water quality and public health and the EPA issued a draft study plan on hydraulic fracturing. Certain states have also considered or imposed reporting obligations relating to the use of hydraulic fracturing techniques.

Additional legislation or regulation could make it easier for parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. There has also been increasing public controversy regarding hydraulic fracturing with regard to use of fracturing fluids, impacts on drinking water supplies, use of water and the potential for impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated in Texas and other states implicating hydraulic fracturing practices.

Legislation, regulation, litigation and enforcement actions at the federal, state or local level that restrict the provision of hydraulic fracturing services could limit the availability and raise the cost of such services, delay completion of new wells and production of our oil and gas, lower our return on capital expenditures and have a material adverse impact on our business, financial condition, results of operations and cash flows and quantities of oil and gas reserves that may be economically produced.

Changes in tax laws may adversely affect our results of operations and cash flows.

President Obama's Proposed Fiscal Year 2013 Budget includes proposed legislation that would, if enacted into law, make significant changes to U.S. tax laws, including the elimination of certain key United States federal income tax incentives currently available to oil and gas exploration and production companies. These changes include, but are not limited to:

- repeal of the percentage depletion allowance for oil and gas properties;
- elimination of current deductions for intangible drilling costs;
- elimination of the domestic manufacturing deduction for oil and gas companies; and
- extension of the amortization period for certain geological and geophysical expenditures.

It is unclear whether any such changes will be enacted or 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 U.S. federal income tax laws could eliminate or otherwise limit certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively impact our financial condition and results of operations.

Competition in the oil and natural gas industry is intense, and we are smaller and have a more limited operating history than many of our competitors.

We compete with major integrated oil and gas companies and independent oil and gas companies in all areas of operation. In particular, we compete for property acquisitions and for the equipment and labor required to operate and develop these properties. Most of our competitors have substantially greater financial and other resources than we have. In addition, larger competitors may be able to absorb the burden of any changes in federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. These competitors may be able to pay more for properties and may be able to define, evaluate, bid for, and purchase a greater number of properties and prospects than we can. Further, our competitors may have technological advantages and may be able to implement new technologies more rapidly than we can. Our ability to explore for natural gas and oil prospects and to acquire additional properties in the future will depend on our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, most of our competitors have operated for a much longer time than we have and have demonstrated the ability to operate through industry cycles.

Our operations substantially depend on the availability of water. Restrictions on our ability to obtain, dispose of or recycle water may impact our ability to execute our drilling and development plans in a timely or cost-effective manner.

Water is an essential component of our drilling and hydraulic fracturing processes. Historically, we have been able to secure water from local landowners and other sources for use in our operations. During the last three years, much of the Southwest region where we operate has experienced extreme drought conditions. As a result of the severe drought, governmental authorities have restricted the use of water subject to their jurisdiction for drilling and hydraulic fracturing to protect the local water supply. If we are unable to obtain water to use in our operations, we may be unable to economically produce oil, NGLs and gas, which could have an adverse effect on our business, financial condition and results of operations.

Moreover, new environmental initiatives and regulations could include restrictions on disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of oil and gas. Compliance with environmental regulations and permit requirements for the withdrawal, storage and use of surface water or ground water necessary for hydraulic fracturing may increase our operating costs and cause delays, interruptions or cessation of our operations, the extent of which cannot be predicted, and all of which would have an adverse effect on our business, financial condition, results of operations and cash flows.

Climate change legislation or regulations regulating emissions of GHGs and VOCs could result in increased operating costs and reduced demand for the oil and gas we produce.

Both houses of Congress have actively considered legislation to reduce emissions of GHGs, and some states have already taken measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap-and-trade programs. Most of these cap-and-trade programs require either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. These allowances are expected to escalate significantly in cost over time.

In addition, in December 2009, the EPA determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, because emissions of such gases are, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. The EPA has also issued final regulations under the NSPS and NESHAP designed to reduce VOCs. The adoption of legislation or regulatory programs to reduce GHG or VOC emissions could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory requirements. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce GHG or VOC emissions could have a material adverse effect on our business, financial condition and results of operations.

Governmental regulations can hinder production.

Domestic oil and natural gas exploration, production and sales are extensively regulated at both the federal and state levels. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, have legal authority to issue, and have issued, rules and regulations affecting the oil and natural gas industry which often are difficult and costly to comply with and which carry substantial penalties for noncompliance. State statutes and regulations require permits for drilling operations, drilling bonds, and reports concerning operations. Most states where we operate also have statutes and regulations governing conservation matters, including the unitization or pooling of properties. Our operations are also subject to numerous laws and regulations governing plugging and abandonment, discharging materials into the environment or otherwise relating to environmental protection. The heavy regulatory burden on the oil and natural gas industry increases its costs of doing business and consequently affects its profitability. Changes in the laws, rules or regulations, or the interpretation thereof, could have a materially adverse effect on our financial condition or results of operation.

Minority or royalty interest purchases do not allow us to control production completely.

We sometimes acquire less than the controlling working interest in oil and natural gas properties. In such cases, it is likely that these properties would not be operated by us. When we do not have controlling interest, the operator or the other co-owners might take actions we do not agree with and possibly increase costs or reduce production income in ways we do not agree with.

Environmental regulations can hinder production.

Oil and natural gas activities can result in liability under federal, state and local environmental regulations for activities involving, among other things, water pollution and hazardous waste transport, storage, and disposal. Such liability can attach not only to the operator of record of the well, but also to other parties that may be deemed to be current or prior operators or owners of the wells or the equipment involved. We have inspections performed on our properties to assure environmental law compliance, but inspections may not always be performed on every well, and structural and environmental problems are not necessarily observable even when an inspection is undertaken.

Government regulations could increase our operating costs

Oil and natural gas operations are subject to extensive federal, state and local laws and regulations relating to the exploration for, and development, production and transportation of, oil and natural gas, as well as safety matters, which may change from time to time in response to economic conditions. Matters subject to regulation by federal, state and local authorities include:

* Permits for drilling operations;
* The production and disposal of water;
* Reports concerning operations;
* Unitization and pooling of properties;
* Road and pipeline construction;
* The spacing of wells;
* Taxation;
* Production rates;
* The conservation of oil and natural gas; and
* Drilling bonds.

Many jurisdictions have at various times imposed limitations on the production of oil and natural gas by restricting the rate of flow for oil and natural gas wells below their actual capacity to produce. During the past few years there has been a significant amount of discussion by legislators and the presidential administration concerning a variety of energy tax proposals. There can be no certainty that any such measure will be passed or what its effect will be on oil and natural gas prices if it is passed. In addition, many states have raised state taxes on energy sources and additional increases may occur, although there can be no certainty of the effect that increases in state energy taxes would have on oil and natural gas prices. Although we believe it is in substantial compliance with applicable environmental and other government laws and regulations, there can be no assurance that significant costs for compliance will not be incurred in the future.

We have not paid cash dividends and do not anticipate paying any cash dividends on our common stock in the foreseeable future.

We anticipate that we will retain all future earnings and other cash resources for the future operation and development of our business. We do not intend to declare or pay any cash dividends in the foreseeable future. Payment of any future dividends will be at the discretion of our Board of Directors after taking into account many factors, including our operating results, financial condition, current and anticipated cash needs, and other factors. Moreover, since the issuance of the Warrants in March 2012, we reclassified $6,895,361 of retained earnings to additional paid-in capital, there may be no capacity for the Company to declare a cash dividend in the near future.

ITEM 1B. – UNRESOLVED STAFF COMMENTS.

None.

ITEM 2-PROPERTIES

Principal Oil and Natural Gas Interests

Block A-49 and Block 6 Field, Andrews County, Texas is a producing oil field located in Andrews, Texas. The Company owns a 74%-100% working interest in five producing oil wells and three injection wells producing out of the Devonian and Ellenburger formations at an approximate depth of 7,000 to 9,000 feet.

Spraberry Trend, Midland County, Texas is a producing oil and natural gas field located 6 miles east of Midland, Texas. The Company owns a 6% to 15% working interest in five oil and natural gas wells producing out of the Spraberry formation at a depth of approximately 7,000 feet.

Flying M Field, Lea County, New Mexico is a producing oil and natural gas field located outside of Hobbs, New Mexico. The Company owns a 39.25% working interest in two oil and natural gas wells producing out of the ABO formation at a depth of approximately 8,300 feet.

Sulimar Field, Chaves County, New Mexico is a producing oil field located 35 miles north east of Artesia, New Mexico. The Company has a 100% working interest in one oil well producing out of the Queen formation at a depth of approximately 1,800 feet.

Apache Field, Caddo County, Oklahoma is a waterflood project producing from the Viola/Bromide formation. The Apache Bromide Unit is located approximately 5 miles west of the town of Apache and 25 miles north of Lawton, Oklahoma. The Company has a 25.23% working interest in the unit which consists of 11 producing oil wells and 9 water injection wells.

North Bilbrey Field, Lea County, New Mexico is a producing natural gas field located outside of Hobbs, New Mexico. The Company owns a 50% working interest in the North Bilbrey #7 federal well producing out of the Atoka formation at approximately 13,000 feet.

Longwood Field, Caddo Parish, Louisiana is a producing natural gas field located north of Greenwood, Louisiana. The Company owns a 12.22% working interest in two natural gas wells producing out of the Cotton Valley formation at a depth of approximately 7,800 feet.

Lusk Field, Lea County, New Mexico is a producing oil and natural gas field located outside of Hobbs, New Mexico. The Company owns an 87.5%-100% working interest in two oil and natural gas wells producing out of the Bonespring and Yates formations in section 15 at depth ranging from approximately 3,400 feet to approximately 10,000 feet and a 43.75% working interest in three wells drilled and producing out of the Bonespring formation. 14.06% working interest in one oil and natural gas well producing out of the Wolfcamp formation in section 14. The Company also owns an 87.5% working interest in one water disposal well.

Loving North Morrow Field, Eddy County, New Mexico is a producing natural gas field located 2 miles west of Loving, New Mexico and 12 miles south east of Carlsbad, New Mexico. The Company owns a 4.3% - 12% working interest in three natural gas wells producing out of the Morrow formation from a depth of approximately 12,300 feet to 12,450 feet.

Chickasha Field, Grady County, Oklahoma is a waterflood project producing from the Medrano Sand. The Rush Springs Medrano Unit is located approximately 65 miles southwest of Oklahoma City, Oklahoma. The Company has a 20.64% working interest in the unit which consists of 21 producing oil and natural gas wells and 11 water injection wells.

West Allen Field, Pontotoc County, Oklahoma is a producing oil and natural gas field located approximately 100 miles south of Oklahoma City, Oklahoma. The Company has a working interest in 52 leases or a total of 224 wells, the leases have multiple wellbores and the Company has plans to participate in the future recompletion of behind pipe zones.

Giddings Field, Fayette County, Texas is in the Austin Chalk field located in various counties surrounding the city of Giddings, Texas. In February 1998, the Company acquired a 97% working interest in the Shade lease. The lease currently has three producing oil and natural gas wells. Oil and natural gas are produced from the Austin chalk formation. The Company will evaluate whether additional reserves can be developed by use of horizontal well technology.

Big Muddy Field, Converse County, Wyoming is a producing oilfield located approximately 30 miles south of Casper, Wyoming. The Company owns a 100% working interest in the Elkhorn and J.C. Kinney lease which consists of three oil wells producing out of the Wallcreek and Dakota formations at depths ranging from approximately 3,200 feet to approximately 4,000 feet.

Serbin Field, Lee and Bastrop Counties Texas is an oil and natural gas field located approximately 50 miles east of Austin and 100 miles west of Houston. The Company has a working interest in 50 producing oil and natural gas wells. Oil and natural gas are produced from the Taylor Sand at depths ranging from approximately 5,300 feet to approximately 5,600 feet; it is a 46-gravity oil sand.

Production

The table below sets forth oil and natural gas production from the Company's net interest in producing properties for each of its last two fiscal years.

Production by State		Oil (bbl) 2013	Oil (bbl) 2012	Gas (mcf) 2013	Gas (mcf) 2012
Louisiana		18	33	8,616	9,200
New Mexico		55,327	49,897	113,559	118,564
Oklahoma		30,189	33,160	32,458	27,610
Texas		12,552	14,955	25,104	24,724
Wyoming		3,666	6,240	-	-
	TOTAL	101,752	104,285	179,737	180,098

The Company's oil and natural gas production is sold on the spot market and the Company does not have any production that is subject to firm commitment contracts. During the year end December 31, 2013, purchases by two customers, Cimarex Energy Co., and Sunoco represented more than 10% of total Company revenues. During the year end December 31, 2012, purchases by three customers, Cimarex Energy Co., Sunoco and Enterprise Crude represented more than 10% of total Company revenues. None of these customers, or any other customers of the Company, has a firm sales agreement with the Company. The Company believes that it would be able to locate alternate customers in the event of the loss of one or all of these customers.

Productive Wells

The table below sets forth certain information regarding the Company's ownership, as of December 31, 2013, of productive wells in the areas indicated.

Productive Wells

State	Oil Gross[1]	Oil Net[2]	Gas Gross[1]	Gas Net[2]
Louisiana	-	-	2	.24
New Mexico	9	3.34	4	.61
Oklahoma	228	51.13	37	4.59
Texas	70	34.12	7	4.10
Wyoming	3	2.58	-	-
Total	310	91.17	50	9.54

[1] A gross well or acre is a well or acre in which a working interest is owned. The number of gross wells is the total number of wells in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

[2] A net well or acre is deemed to exist when the sum of fractional ownership working interests in gross wells or acres equals one. The number of net wells or acres is the sum of the fractional working interests owned in gross wells or acres expressed as whole numbers and fractions thereof.

Drilling Activity

The tables below set forth certain information regarding the number of productive and dry exploratory and development wells drilled for the fiscal year ended December 31, 2013.

	Exploratory Wells		Development Wells	
State	**Productive**	**Dry**	**Productive**	**Dry**
Louisiana	--	--	--	--
New Mexico	--	--	1	--
Oklahoma	--	--	--	--
Texas	--	--	--	1
Wyoming	--	--	--	--
Total	--	--	1	1

Reserves

Estimated Proved Reserves/Developed and Undeveloped Reserves: The following tables set forth the estimated proved developed and proved undeveloped oil and gas reserves of FieldPoint for the years ended December 31, 2013 and 2012. See Notes 11 and 12 to the Consolidated Financial Statements and the following discussion.

Estimated Proved Reserves

Proved Reserves	Oil (Bbls)	Gas (Mcf)
Estimated quantity, January 1, 2012	1,200,264	2,269,548
Revisions of previous estimates	13,854	48,955
Extensions and discoveries	115,093	209,930
Production	(104,285)	(180,098)
Estimated quantity, December 31, 2012	1,224,926	2,348,335
Revisions of previous estimates	(202,450)	(322,413)
Extensions and discoveries	99,988	143,343
Production	(101,752)	(179,737)
Estimated quantity, December 31, 2013	1,020,712	1,989,528

Proved Developed and Undeveloped Reserves

	Developed	Undeveloped	Total
Oil (Bbls)			
December 31, 2013	916,139	104,573	1,020,712
December 31, 2012	983,900	241,026	1,224,926
Gas (Mcf)			
December 31, 2013	1,834,899	154,629	1,989,528
December 31, 2012	1,898,705	449,630	2,348,335

Proved Undeveloped Reserves

As of December 31, 2013, we had 130,344 BOE of proved undeveloped ("PUD") reserves, which is a decrease of 185,620 BOE or 59%, compared with 315,964 BOE of PUD reserves at December 31, 2012. As a percent of our total proved reserves, our PUD reserves decreased from 20% in 2012 to 10% in 2013 due to our ongoing development of our East Lusk field and to revisions to undeveloped properties held more than five years.

The following table summarizes the changes in our PUD reserves during 2013.

	Oil (Bbls)	Gas (Mcf)	Total (BOE)
Balance – December 31, 2012	241,026	449,630	315,964
Extensions and discoveries	90,970	143,342	114,860
Revisions to previous estimates	(113,745)	(184,999)	(144,578)
Conversion to proved developed reserves	(113,678)	(253,344)	(155,902)
Balance – December 31, 2013	104,573	154,629	130,344

The following table sets forth our PUD reserves converted to proved developed reserves during 2013 and 2012 and the net investment required to convert PUD reserves to proved developed reserves during the year.

	Proved Undeveloped Reserves Converted to Proved Developed Reserves			Investment in Conversion of Proved Undeveloped Reserves to Proved Developed Reserves
Year Ended December 31,	Oil (Bbls)	Gas (Mcf)	Total (BOE)	
2012	69,455	119,280	89,335	$ 3,000,000
2013	113,678	253,344	155,902	3,000,000
Total	183,133	372,624	245,237	$ 6,000,000

The following table sets forth our estimated future development costs relating to the development of PUD reserves:

Year Ended December 31,	Estimated Future Development Costs
2014	$ 340,800
2015	2,843,040
2016	20,000
2017	-
Total	$ 3,203,840

We monitor fluctuations in commodity prices, drilling and completion costs, operating expenses and drilling success to determine adjustments to our drilling and development program. We plan to drill the East Lusk Federal Well #4 starting late 2014. Based on current expectations for cash flows, commodity prices and operating costs and expenses, all PUD reserves are scheduled to be drilled before the end of 2017.

Preparation of Proved Reserves Estimates

Internal Controls Over Preparation of Proved Reserves Estimates

Our policies regarding internal controls over the recording of reserve estimates require reserve estimates to be in compliance with SEC rules, regulations and guidance and prepared in accordance with generally accepted petroleum engineering principles. Our proved oil and natural gas reserves as of December 31, 2013 and December 31, 2012 have been estimated by Fletcher Lewis Engineering, Inc., & PGH Engineers and additionally by Joe C. Neal and Associates as of December 31, 2013. These independent consultants are responsible for overseeing the preparation of our reserve estimates and for internal compliance of our reserve estimates with SEC rules, regulations and generally accepted petroleum engineering principles. Phillip Roberson, President and COO, provides company data (such as well ownership interests, oil and gas prices, production volumes and well operating costs) to consulting petroleum engineers and is the primary Company employee responsible for reviewing their use of our data and estimation of our reserves. Mr. Roberson, who has over fifteen years of experience in various capacities in the oil and gas exploration industry, provides our consulting petroleum engineers with technical data (such as well logs, geological information and well histories). Mr. Roberson also reviews the preliminary reserve estimates and the financial inputs in the estimates. Mr. Roberson calculates the disclosed changes in reserve estimates and the disclosed changes in the Standardized Measure relating to proved oil and gas reserves.

As defined in the Securities and Exchange Commission Rules, proved reserves are the estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include considerations of changes in existing prices provided only by contractual arrangements but not on escalations based on future conditions. Reservoirs are considered proved if economic production is supported by either actual production or conclusive formation tests. Reserves which can be produced economically through application of improved recovery techniques, such as fluid injections, are included in the "proved" classification when successful testing by a pilot project, or the operations of an installed program in the reservoir, provide support for the engineering analysis on which the project or program was based. Due to the inherent uncertainties and the limited nature of reservoir data, such estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of these reserves may be substantially different from the original estimate. Revisions result primarily from new information obtained from development drilling and production history and from changes in economic factors.

For information concerning the standardized measure of discounted future net cash flows, estimated future net cash flows and present values of such cash flows attributable to our proved oil and gas reserves as well as other reserve information, see Notes 11 and 12 to the Consolidated Financial Statements.

Technologies Used in Preparation of Proved Reserves Estimates

Estimates of reserves were prepared by the use of standard geological and engineering methods generally accepted by the petroleum industry. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data and production history.

When applicable, the volumetric method was used to estimate the original oil in place, or OOIP, and the original gas in place, or OGIP. Structure and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation. When adequate data were available and when circumstances justified, material balance and other engineering methods were used to estimate OOIP or OGIP.

Estimates of ultimate recovery were obtained after applying recovery factors to OOIP or OGIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties and the production histories. When applicable, material balance and other engineering methods were used to estimate recovery factors. An analysis of reservoir performance, including production rate, reservoir pressure and gas-oil ratio behavior, was used in the estimation of reserves.

Because our proved reserves are located in depletion-type reservoirs and reservoirs whose performance demonstrates a reliable decline in producing-rate trends, reserves were also estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-declining curves, reserves were estimated only to the limits of economic production or to the limit of the production licenses or leases as appropriate.

Reserves Sensitivity Analysis

As permitted by the recently adopted SEC regulations, we have elected not to undertake a sensitivity analysis of our reserves estimates.

Oil and Gas Reserves Reported to Other Agencies: We did not file any estimates of total proved net oil or gas reserves with, or include such information in reports to, any federal authority or agency during the fiscal year ended December 31, 2013, or subsequently thereafter.

Title Examinations: Oil and Gas: As is customary in the oil and gas industry, we perform only a perfunctory title examination at the time of acquisition of undeveloped properties. Prior to the commencement of drilling, in most cases, and in any event where we are the Operator, a thorough title examination is conducted and significant defects remedied before proceeding with operations. We believe that the title to our properties is generally acceptable to a reasonably prudent operator in the oil and gas industry. The properties we own are subject to royalty, overriding royalty and other interests customary in the industry, liens incidental to operating agreements, current taxes and other burdens, minor encumbrances, easements and restrictions. We do not believe that any of these burdens materially detract from the value of the properties or will materially interfere with our business.

We have purchased producing properties on which no updated title opinion was prepared. In some, but not all, cases, we have retained third party certified petroleum landmen to review title.

Acreage

The following tables set forth the gross and net acres of developed and undeveloped oil and natural gas leases in which the Company had working interest and royalty interest as of December 31, 2013. The category of "Undeveloped Acreage" in the table includes leasehold interest that already may have been classified as containing proved undeveloped reserves.

	Developed		Undeveloped	
State	**Gross [(1)]**	**Net [(2)]**	**Gross [(1)]**	**Net [(2)]**
Louisiana	320	78	-	-
New Mexico	2,400	896	480	262
Oklahoma	8,826	1,300	200	19
Texas	2,911	1,182	1,360	1,000
Wyoming	560	268	2,306	1,880
Total	15,017	3,724	4,346	3,161

[1] A gross well or acre is a well or acre in which a working interest is owned. The number of gross wells is the total number of wells in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

[2] A net well or acre is deemed to exist when the sum of fractional ownership working interests in gross wells or acres equals one. The number of net wells or acres is the sum of the fractional working interests owned in gross wells or acres expressed as whole numbers and fractions thereof.

ITEM 3-LEGAL PROCEEDINGS

None.

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

None.

PART II

ITEM 5-MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Since September 20, 2005 the Company's common stock has been traded and listed on the NYSE MKT, LLC, formerly the NYSE Amex and before that the NYSE Alternext and formerly the American Stock Exchange, under the symbol "FPP." Prior to September 20, 2005, the Company's common stock was listed on the OTC bulletin board under the symbol FPPC. The following sets forth the high and low closing prices of our common stock on the NYSE MKT, LLC for the periods shown.

FISCAL 2012	CLOSING PRICE	
	HIGH	LOW
First Quarter	6.00	3.81
Second Quarter	4.69	3.15
Third Quarter	5.21	3.60
Fourth Quarter	4.80	3.42
FISCAL 2013		
	HIGH	LOW
First Quarter	4.20	3.74
Second Quarter	4.20	3.40
Third Quarter	4.74	3.71
Fourth Quarter	5.18	3.90

At March 27, 2014, the approximate number of shareholders of record was 303. The Company has not paid any cash dividends on its common stock and does not expect to do so in the foreseeable future.

EQUITY COMPENSATION PLAN INFORMATION

	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuances under equity compensation plans (excluding securities reflected in column
Equity compensation plans approved by security holders	-	-	-
Equity compensation plans not approved by security holders	-	-	-
Total	-	-	-

ITEM 6 SELECTED FINANCIAL DATA

We have set forth below certain selected financial data. The information has been derived from the financial statements, financial information and notes thereto included elsewhere in this report.

	Years Ended December 31,	
	2013	**2012**
Statements of Operations Data:		
Total revenues	$10,541,231	$10,402,889
Operating expenses	8,245,675	7,314,380
Net income	1,278,997	2,112,263
Basic earnings per share	$ 0.16	$ 0.26
Shares used in computing basic earnings per share	8,062,167	8,006,959
Diluted earnings per share	$ 0.15	$ 0.25
Shares used in computing diluted earnings per share	8,385,253	8,452,429

	December 31,	
Balance Sheet Data:	**2013**	**2012**
Working capital	$ 3,459,051	$ 2,109,552
Total assets	24,962,828	23,135,430
Total liabilities	12,412,766	11,953,965
Stockholders' equity	12,550,062	11,181,465

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

The following discussion should be read in conjunction with the Company's Financial Statements, and respective notes thereto, included elsewhere herein. The information below should not be construed to imply that the results discussed herein will necessarily continue into the future or that any conclusion reached herein will necessarily be indicative of actual operating results in the future. Such discussion represents only the best present assessment of the management of FieldPoint Petroleum Corporation.

Overview

FieldPoint Petroleum Corporation derives our revenues from our operating activities including sales of oil and natural gas and operating oil and natural gas properties. Our capital for investment in producing oil and natural gas properties has been provided by cash flow from operating activities and from bank financing. We categorize our operating expenses into the categories of production expenses and other expenses.

On June 6, 2013, the Founder and President of FieldPoint Petroleum Corporation, Mr. Ray D. Reaves, died in an automobile accident near Giddings, Texas. On June 9, 2013, the Board of Directors elected Mr. Roger D. Bryant to serve as our executive Chairman and granted him executive powers to oversee the management of the Company. Mr. Bryant continues to serve as our highest ranking executive officer. On June 14, 2013, Mr. Phillip H. Roberson was engaged to take operational control of the business, and on July 1, 2013, he was named COO/CFO. On December 10, 2013, Mr. Roberson was named President of the Company. During this transitional period, every member of the Board of Directors has been actively involved with the ongoing efforts to ensure no loss in continuity of the business. We have received overwhelming support from shareholders, bankers, attorneys, accountants, contractors, suppliers, field operators and partners, all of which have expressed great respect for Mr. Reaves and their personal loss from this tragic event.

We completed drilling the East Lusk 15 Federal #3 on July 31, 2013. The well produced 17,997 net barrels of oil during the year ended December 31, 2013.

Results of Operations

	Years Ended December 31,	
	2013	2012
Revenues:		
Oil sales	$ 9,520,591	$ 9,457,292
Natural gas sales	804,789	783,336
Total	$ 10,325,380	$ 10,240,628
Sales volumes:		
Oil (Bbls)	101,752	104,285
Natural gas (Mcf)	179,737	180,098
Total (BOE)	131,708	134,301
Average sales prices		
Oil ($/Bbl)	$ 93.57	$ 90.69
Natural gas ($/Mcf)	4.48	4.35
Total ($/BOE)	$ 78.40	$ 76.25

Costs and expenses ($/BOE)		
Lease operating	$ 21.59	$ 16.39
Production taxes	8.10	8.38
Depletion and depreciation	18.18	15.58
Exploration expense	1.16	-
Impairment of oil and natural gas properties	3.69	1.52
Accretion of discount on asset retirement obligations	0.73	0.68
General and administrative	9.16	11.92
Total	$ 62.61	$ 54.47

Revenues
Oil and natural gas sales revenues increased by $84,752 or 1%, primarily due to increased commodity prices. Oil sales increased $63,000 due to increased prices that contributed $293,000 to the increase in oil sales revenues offset by $230,000 due to lower production. Oil sales volumes decreased by 2%, primarily due to downtime on wells undergoing remedial repairs in 2013. Natural gas sales increased $21,000 or 3%, due primarily to increased natural gas commodity prices in 2013. Oil and natural gas prices have been volatile during 2013 and we expect this to continue. Our oil and natural gas sales revenue will be highly dependent on commodity prices in 2014.

Lease Operating Expenses
Lease operating expenses increased by $641,483 or 29% due to increased cost of remedial repairs during 2013 and costs associated with production from two new wells completed in December 2012 and July 2013. Cost increased by $5.19 per barrel equivalent (BOE) or 32% in 2013 as compared to 2012. Increased costs contributed approximately $684,000 and was offset approximately $43,000 as a result of lower sales volumes from the prior year. Many of our properties are mature and bear high operating expense which could result in increased operating costs in the future.

Production Taxes
Production taxes decreased $58,470 or 5%, primarily the result of decreased oil and natural gas sales volumes and higher costs per barrel equivalent. Production taxes amounted to approximately 10% of oil and natural gas sales revenue during 2013 and 11% during 2012. The decrease was a result of an unanticipated charge of previous years' taxes paid to the Apache Tribe in 2012. We expect production taxes to range between 8% and 10% of oil and natural gas sales revenue.

Depletion and Depreciation
Depletion and depreciation expense increased by $303,000 or 14%. The increase in depletion and depreciation was primarily due to depletion on two new wells completed in September 2012 and July 2013.

Impairment of Oil and Natural Gas Properties
During the year ended December 31, 2013 we recorded impairment of $485,999 on the Sprayberry property. Impairment of $204,190 was recorded during the year ended December 31, 2012 on the Loving property.

General and Administrative Expense
General and administrative expenses decreased $394,177 or 25% primarily due to decreases in compensation expense, professional services fees and bad debt expense. Significant components of general and administrative expenses include personnel-related costs and professional services fees. We expect our general and administrative expenses to increase next year.

Other Income (Expense)
Interest expense decreased in 2013 by $5,104 or 2%. During the year ended December 31, 2013 we had an unrealized loss of $4,000 on commodity derivatives and no realized gains during 2013. We sold our interest in the Stauss property at a gain of $4,000 in 2013. During the year ended December 31, 2012 we realized a $254,151 gain on commodity derivatives. Also in 2012, we sold our interest in the South Vacuum property at a gain of $204,000.

Liquidity and Capital Resources

Cash flow provided by operating activities was approximately $4.7 million for the year ended December 31, 2013, compared to $3.3 million for the year ended December 31, 2012. The increase in cash flow from operating activities was primarily due to changes to accounts payable.

In 2013 we used our operating cash flow along with cash on hand to fund $3.5 million of development of oil and natural gas properties. We sold our interest in the Stauss #1 property for $5,000. These were the primary components of cash used in investing activities in 2013. In 2012 we used our operating cash flow along with cash on hand to fund $4.4 million of development of oil and natural gas properties. We sold our interest in the South Vacuum property for $204,000. These were the primary components of cash used in investing activities in 2012.

Cash flow provided by financing activities for the year ended December 31, 2013, was $89,600 from the exercise of 22,400 of our outstanding publicly traded common stock purchase warrants at an exercise price of $4.00 per share. Cash provided by financing activities for 2012 was $193,589. We sold 60,761 shares of common stock for $257,358 and related expenses were $63,769, pursuant to an At Market Issuance Sales Agreement with MLV & Co., LLC.

Capital Requirements

We believe we will be able to meet our current operating needs through internally generated cash from operations and borrowings under our revolving credit facility. As of December 31, 2013, we had working capital of approximately $3.5 million and approximately $4.3 million of borrowing capacity under our line of credit based on a borrowing base of $11 million. The borrowing base is subject to redetermination based on the value of proved reserves, and could be increased or decreased during 2014.

Although we had no significant commitments for capital expenditures at December 31, 2013, we anticipate continued investments in oil and natural gas properties during 2014. If bank credit is not available, we may not be able to continue to invest in strategic oil and natural gas properties. We cannot predict how oil and natural gas prices will fluctuate during 2014 and what effect they will ultimately have on our operations, but we believe that we will be able to generate sufficient cash from operations to service our bank debt and provide for maintaining current production of its oil and natural gas properties. The timing of most capital expenditures is relatively discretionary. Therefore, we can plan expenditures to coincide with available funds in order to minimize business risks. As of December 31, 2013, we had $143,902 of capital items in accounts payable that will be paid from working capital.

On January 1, 2014 FieldPoint Petroleum Corp. ("FieldPoint") signed an exploration agreement ("the agreement") with Riley Exploration, LLC ("Riley"). The agreement provides for an Area of Mutual Interest ("AMI") and a 90 day due diligence period, after which both Companies will cross assign their working interest and vertical wells with a targeted ownership for FieldPoint of 25%. The agreement also provides for a development plan with the intent to drill up to twelve horizontal wells during the initial twelve month period after closing. FieldPoint may elect to be the drilling operator of every fifth well. The agreement also provides for a standard Joint Operating Agreement which allows either partner to participate or decline to participate in every well with no obligatory wells.

Contractual Obligations and Commitments

We have contractual obligations and commitments that affect our consolidated results of operations, financial condition and liquidity. The following table is a summary of our significant cash contractual obligations:

	Obligation Due in Period				
Cash Contractual Obligations	2014	2015	2016	Thereafter	Total
	(in thousands)				
Credit facility (secured)	$ -	$ -	$ 6,740	$ -	$ 6,740
Interest on credit facility	264	264	197	-	725
Total	$ 264	$ 264	$ 6,937	$ -	$ 7,465

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our accounting policies are described in Note 1 of Notes to Consolidated Financial Statements in Item 8. We prepare our Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America ("U.S. GAAP"), which require us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the year. Actual results could differ from those estimates. We consider the following policies to be most critical in understanding the judgments that are involved in preparing our financial statements and the uncertainties that could impact our results of operations, financial condition and cash flows.

Successful Efforts Method of Accounting

We account for our exploration and development activities utilizing the successful efforts method of accounting. Under this method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Oil and natural gas lease acquisition costs are also capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for oil and natural gas leases, are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities. The sale of a partial interest in a proved property is accounted for as a cost recovery and no gain or loss is recognized as long as this treatment does not significantly affect the unit-of-production amortization rate. A gain or loss is recognized for all other sales of producing properties.

The application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as developmental or exploratory which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Wells may be completed that are assumed to be productive and actually deliver oil and natural gas in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. The evaluation of oil and natural gas leasehold acquisition costs requires managerial judgment to estimate the fair value of these costs with reference to drilling activity in a given area.

The successful efforts method of accounting can have a significant impact on the operational results reported when we enter a new exploratory area in hopes of finding an oil and natural gas field that will be the focus of future developmental drilling activity. The initial exploratory wells may be unsuccessful and will be expensed. Seismic costs can be substantial which will result in additional exploration expenses when incurred.

Reserve Estimates

Estimates of oil and natural gas reserves, by necessity, are projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable oil and natural gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effects of regulations by governmental agencies and assumptions governing future oil and natural gas prices, future operating costs, severance taxes, development costs and workover costs, all of which may in fact vary considerably from actual results. The future drilling costs associated with reserves assigned to proved undeveloped locations may ultimately increase to an extent that these reserves may be later determined to be uneconomic. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows expected therefrom may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of our oil and natural gas properties and/or the rate of depletion of the oil and natural gas properties. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material.

Impairment of Oil and Natural Gas Properties

We review our oil and natural gas properties for impairment whenever events and circumstances indicate a decline in the recoverability of their carrying value. We estimate the expected future cash flows of our oil and natural gas properties and compare such future cash flows to the carrying amount of our oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will adjust the carrying amount of the oil and natural gas properties to their fair value. The factors used to determine fair value include, but are not limited to, estimates of proved reserves, commodity pricing, future production estimates, anticipated capital expenditures, and a discount rate commensurate with the risk associated with realizing the expected cash flows projected. There were $485,999 of impairments on our proved oil and natural gas properties in 2013 and $204,190 of impairments of oil and natural gas properties in 2012.

Reporting Requirements

Because our common stock is publicly traded, we are subject to certain rules and regulations of federal, state and financial market exchange entities charges with the protection of investors and the oversight of companies whose securities are publicly traded. These entities, including the SEC and the NYSE MKT, LLC, have issued requirements and regulations and are currently developing additional regulations and requirements in response to laws, enacted by Congress, most notably the Sarbanes-Oxley Act 2002 and SEC reporting regulations which became effective January 1, 2010. Our compliance with current rules requires the commitment of significant managerial resources. We concluded that our internal control over financial reporting were effective as of December 31, 2013.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We periodically enter into certain commodity price risk management transactions to manage our exposure to oil and natural gas price volatility. These transactions may take the form of futures contracts, swaps or options. All data relating to our derivative positions is presented in accordance with requirements of authoritative accounting guidance. Unrealized gains and losses related to the change in fair value of derivative contracts that qualify and are designated as cash flow hedges are recorded as other comprehensive income or loss and such amounts are reclassified to oil and natural gas sales revenues as the associated production occurs. Derivative contracts that do not qualify for hedge accounting treatment are recorded as derivative assets and liabilities at fair value in the consolidated balance sheet, and the associated unrealized gains and losses are recorded as current expense or income in the consolidated statement of operations. While such derivative contracts do not qualify for hedge accounting, management believes these contracts can be utilized as an effective component of commodity price risk management activities. At December 31, 2013 the company had $4,000 in open positions. At December 31, 2012, there were no open positions. We did have derivative transactions during 2013 and 2012.

ITEM 8 FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
FieldPoint Petroleum Corporation and Subsidiaries
Austin, Texas

We have audited the accompanying consolidated balance sheets of FieldPoint Petroleum Corporation and subsidiaries (the "Company") as of December 31, 2013 and 2012, and the related consolidated statements of operations, changes in stockholders' equity and cash flows for each of the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of FieldPoint Petroleum Corporation and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the years then ended, in conformity with U.S. generally accepted accounting principles.

/s/*Hein & Associates LLP*

Dallas, Texas
March 27, 2014

FIELDPOINT PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS

ASSETS

	December 31, 2013	December 31, 2012
CURRENT ASSETS:		
Cash and cash equivalents	$ 2,648,487	$ 1,408,075
Certificates of deposit	44,721	44,702
Accounts receivable:		
Oil and natural gas sales	1,078,333	1,193,495
Joint interest billings, less allowance for doubtful accounts of approximately $174,000 each period	226,743	229,406
Income taxes receivable	319,097	196,555
Deferred income tax asset-current	64,000	171,000
Prepaid expenses and other current assets	64,751	42,349
Total current assets	4,446,132	3,285,582
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties (successful efforts method)	35,256,754	32,210,252
Other equipment	62,836	52,113
Less accumulated depletion and depreciation	(14,802,894)	(12,412,517)
Net property and equipment	20,516,696	19,849,848
Total assets	$ 24,962,828	$ 23,135,430

LIABILITIES AND STOCKHOLDERS' EQUITY

	2013	2012
CURRENT LIABILITIES:		
Accounts payable and accrued expenses	$ 742,493	$ 889,796
Oil and natural gas revenues payable	240,588	286,234
Unrealized loss on commodity derivatives	4,000	-
Total current liabilities	987,081	1,176,030
LINE OF CREDIT	6,740,000	6,740,000
DEFERRED INCOME TAXES	2,973,000	2,442,000
ASSET RETIREMENT OBLIGATION	1,712,685	1,595,935
Total liabilities	12,412,766	11,953,965
COMMITMENTS AND CONTINGENCIES (Notes 9 and 10)		
STOCKHOLDERS' EQUITY:		
Common stock, $.01 par value, 75,000,000 shares authorized; 8,993,336 and 8,970,936 shares issued, respectively; and 8,066,336 and 8,043,936 outstanding, respectively	89,933	89,709
Additional paid-in capital	11,751,298	11,661,922
Retained earnings	2,675,723	1,396,726
Treasury stock, 927,000 shares, each period, at cost	(1,966,892)	(1,966,892)
Total stockholders' equity	12,550,062	11,181,465
Total liabilities and stockholders' equity	$ 24,962,828	$ 23,135,430

See accompanying notes to these consolidated financial statements.

FIELDPOINT PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

	DECEMBER 31, 2013	DECEMBER 31, 2012
REVENUE:		
Oil and natural gas sales	$ 10,325,380	$ 10,240,628
Well operational and pumping fees	25,877	68,265
Disposal fees	189,974	93,996
Total revenue	10,541,231	10,402,889
COSTS AND EXPENSES:		
Lease operating	3,909,637	3,326,624
Depletion and depreciation	2,395,000	2,092,000
Exploration expense	152,650	-
Impairment of oil and natural gas properties	485,999	204,190
Accretion of discount on asset retirement obligations	96,000	91,000
General and administrative	1,206,389	1,600,566
Total costs and expenses	8,245,675	7,314,380
OPERATING INCOME	2,295,556	3,088,509
OTHER INCOME (EXPENSE):		
Interest income	2,783	2,389
Interest expense	(259,016)	(264,120)
Unrealized loss on commodity derivatives	(4,000)	-
Realized gain on commodity derivatives	-	254,151
Gain on sale of oil and natural gas property	4,000	204,000
Miscellaneous	6,744	1,334
Total other income (expense)	(249,489)	197,754
INCOME BEFORE INCOME TAXES	2,046,067	3,286,263
INCOME TAX PROVISION – current	(129,070)	(312,000)
INCOME TAX PROVISION – deferred	(638,000)	(862,000)
TOTAL INCOME TAX PROVISION	(767,070)	(1,174,000)
NET INCOME	$ 1,278,997	$ 2,112,263
EARNINGS PER SHARE:		
BASIC	$ 0.16	$ 0.26
DILUTED	$ 0.15	$ 0.25
WEIGHTED AVERAGE SHARES OUTSTANDING:		
Basic	8,062,167	8,006,959
Diluted	8,385,253	8,452,429

See accompanying notes to these consolidated financial statements.

FIELDPOINT PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

FOR THE YEARS ENDED DECEMBER 31, 2013 AND 2012

	Common Stock		Additional Paid-in	Retained	Treasury Stock		
	Shares	Amount	Capital	Earnings	Shares	Amount	Total
BALANCES, January 1, 2012	8,910,175	$ 89,101	$ 4,573,580	$ 6,179,824	927,000	$ (1,966,892)	$ 8,875,613
At-the-market offering	60,761	608	192,981	-	-	-	193,589
Stock warrant dividend	-	-	6,895,361	(6,895,361)	-	-	-
Net income	-	-	-	2,112,263	-	-	2,112,263
BALANCES, December 31, 2012	8,970,936	89,709	11,661,922	1,396,726	927,000	(1,966,892)	11,181,465
Common stock issued from exercise of warrants	22,400	224	89,376	-	-	-	89,600
Net income	-	-	-	1,278,997	-	-	1,278,997
BALANCES, December 31, 2013	8,993,336	$ 89,933	$ 11,751,298	$ 2,675,723	927,000	$ (1,966,892)	$ 12,550,062

See accompanying notes to these consolidated financial statements.

FIELDPOINT PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	DECEMBER 31, 2013	DECEMBER 31, 2012
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 1,278,997	$ 2,112,263
Adjustments to reconcile net income to net cash provided by operating activities:		
Gain on sale of oil and natural gas properties	(4,000)	(204,000)
Unrealized loss on commodity derivatives	4,000	-
Depletion and depreciation	2,395,000	2,092,000
Exploration expense	152,650	-
Impairment of oil and natural gas properties	485,999	204,190
Deferred income tax expense	638,000	862,000
Accretion of discount on asset retirement obligations	96,000	91,000
Changes in current assets and liabilities:		
Accounts receivable	117,825	(206,667)
Income taxes receivable	(122,542)	135,579
Prepaid expenses and other current assets	(22,402)	79,396
Accounts payable and accrued expenses	(291,205)	(1,858,934)
Oil and natural gas revenues payable	(45,646)	27,105
Other	(19)	(233)
Net cash provided by operating activities	4,682,657	3,333,699
CASH FLOWS FROM INVESTING ACTIVITIES:		
Additions to oil and natural gas properties and other equipment	(3,536,845)	(4,360,806)
Proceeds from the sale of oil and natural gas properties	5,000	204,000
Net cash used in investing activities	(3,531,845)	(4,156,806)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Sale of common stock	-	193,589
Common stock issued from the exercise of warrants	89,600	-
Net cash provided by financing activities	89,600	193,589
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	1,240,412	(629,518)
CASH AND CASH EQUIVALENTS, beginning of year	1,408,075	2,037,593
CASH AND CASH EQUIVALENTS, end of the year	$ 2,648,487	$ 1,408,075
SUPPLEMENTAL INFORMATION:		
Cash paid during the year for interest	$ 199,405	$ 264,120
Cash paid during the year for income taxes	$ 334,595	$ 5,410
Capital items in accounts payable	$ 143,902	$ 210,518

See accompanying notes to these consolidated financial statements.

FIELDPOINT PETROLEUM CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Nature of Operations

FieldPoint Petroleum Corporation (the "Company", "we" or "our") is incorporated under the laws of the state of Colorado. We are engaged in the acquisition, operation and development of oil and natural gas properties, which are located in Louisiana, New Mexico, Oklahoma, South Central Texas and Wyoming as of December 31, 2013 and 2012.

Consolidation Policy

Our consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries, Bass Petroleum, Inc., and Raya Energy Corp. All material intercompany accounts and transactions have been eliminated in consolidation.

Cash and Cash Equivalents

We consider all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents. At times, we maintain deposit balances in excess of FDIC insurance limits. We have not experienced any losses in such accounts and believe we are not exposed to any significant credit risk on cash and cash equivalents.

Certificates of Deposit

Certificates of deposit have original maturities ranging from three months to one year and are recorded at fair value on the balance sheet in current assets. Changes in fair value during the period are classified as realized or unrealized holding gains in other income.

Oil and Natural Gas Properties

Our oil and natural gas properties consisted of the following at December 31:

	2013	2012
Mineral interests in properties:		
Unproved properties	$ 850,000	$ 850,000
Proved properties	14,250,230	15,098,352
Wells and related equipment and facilities	20,156,524	16,261,900
Total costs	35,256,754	32,210,252
Less accumulated depletion and depreciation	(14,763,266)	(12,378,889)
	$ 20,493,488	$ 19,831,363

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, to drill and equip exploratory wells that find proved reserves, to drill and equip development wells and related asset retirement costs are capitalized. Costs to drill exploratory wells are capitalized pending determination of whether the wells have found proved reserves. If we determine that the wells have not found proved reserves, the costs are charged to expense. There were no exploratory wells capitalized pending determinations of whether the wells found proved reserves at December 31, 2013 or 2012. 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, 2013, we have capitalized no interest costs because our exploration and development projects generally last less than six months. Costs 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 depletion and depreciation are eliminated from the property accounts, and the resulting gain or loss is recognized. On the sale of a partial unit of proved property, the amount received is treated as a reduction of the cost of the interest retained.

Capitalized amounts attributable to proved oil and natural gas properties are depleted by the unit-of-production method of proved reserves using the unit conversion ratio of 6 Mcf of gas to 1 bbl of oil. Depletion and depreciation expense for oil and natural gas producing property and related equipment was $2,389,000 and $2,086,000 for the years ended December 31, 2013 and 2012, respectively.

Unproved oil and natural gas properties that are individually significant are periodically assessed for impairment of value, and a loss is recognized at the time of impairment by providing an impairment allowance. No impairment of unproved properties was recorded during the years ended December 31, 2013 or 2012.

Capitalized costs related to proved oil and natural gas properties, including wells and related equipment and facilities, are evaluated for impairment based on an analysis of undiscounted future net cash flows. If undiscounted cash flows are insufficient to recover the net capitalized costs related to proved properties, then we recognize an impairment charge in income from operations equal to the difference between the net capitalized costs related to proved properties and their estimated fair values based on the present value of the related future net cash flows, which is a non-recurring fair value measurement classified as Level 3 in the fair value hierarchy. We recorded an impairment on our proved oil and natural gas properties of $485,999 and $204,190 during the years ended December 31, 2013 and 2012, respectively.

On the sale of an entire interest in an unproved property for cash or cash equivalent, 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.

Oil and Natural Gas Sales Receivable

Oil and natural gas sales receivable principally consist of accrued oil and natural gas sales proceeds receivable and are typically collected within 35 days from the end of the month in which the related quantities are produced. We ordinarily do not require collateral for such receivables, nor do we charge interest on past due balances. We periodically review accounts receivable for collectability and reduce the carrying amount of the accounts receivable by an allowance. No such allowance was indicated at December 31, 2013 or 2012. As of December 31, 2013, our accounts receivable were primarily with several independent purchasers of our crude oil and natural gas production. At December 31, 2013, we had balances due from two customers which were greater than 10% of our accounts receivable related to crude oil and natural gas production. These two customers accounted for 75% of accounts receivable at December 31, 2013. At December 31, 2012, we had balances due from two customers which were greater than 10% of our accounts receivable related to crude oil and natural gas production. These two customers accounted for 63% of accounts receivable at December 31, 2012. In the event that one or more of these significant customers ceases doing business with us, we believe that there are potential alternative customers with whom we could establish new relationships and that those relationships will result in the replacement of one or more lost customers.

Joint Interest Billings Receivable and Oil and Natural Gas Revenues Payable

Joint interest billings receivable represent amounts receivable for lease operating expenses and other costs due from third party working interest owners in the wells that the Company operates. The receivable is recognized when the cost is incurred and the related payable and the Company's share of the cost is recorded. We often have the ability to offset amounts due against the participant's share of production from the related property.

The Company uses the reserve for bad debt method of valuing doubtful joint interest billings receivable based on historical experience, coupled with a review of the current status of existing receivables. The balance of the reserve for doubtful accounts, deducted against joint interest billings receivable to properly reflect the realizable value was approximately $174,000 at December 31, 2013 and 2012.

Oil and natural gas revenues payable represents amounts due to third party revenue interest owners for their share of oil and natural gas revenue collected on their behalf by the Company. The payable is recorded when the Company recognizes oil and natural gas sales and records the related oil and natural gas sales receivable.

Other Property

Other assets classified as property and equipment are primarily office furniture and equipment and vehicles, which are carried at cost. Depreciation is provided using the straight-line method over estimated useful lives ranging from three to five years. Gain or loss on retirement or sale or other disposition of assets is included in income in the period of disposition. Depreciation expense for other property and equipment was $6,000 for each of the years ended December 31, 2013 and 2012.

Asset Retirement Obligations

Our financial statements reflect our asset retirement obligations, consisting of future plugging and abandonment expenditures related to our oil and natural gas properties, which can be reasonably estimated. The asset retirement obligation is recorded at fair value on a discounted basis as a liability at the asset's inception, with an offsetting increase to producing properties on the consolidated balance sheets. Periodic accretion of the discount of the estimated liability is recorded as an expense in the consolidated statements of operations.

The following is a reconciliation of the Company's asset retirement obligations for the years ended December 31:

	2013	2012
Asset retirement obligation at January 1,	$ 1,595,935	$ 1,515,002
Accretion of discount	96,000	91,000
Liabilities incurred during the year	22,000	22,000
Liabilities settled during the year	(1,250)	(32,067)
Asset retirement obligation at December 31,	$ 1,712,685	$ 1,595,935

The entire balance was classified as a non-current liability at December 31, 2013 and 2012.

Income Taxes

Income taxes are provided for the tax effects of transactions reported in the financial statements and consist of taxes currently due, if any, plus net deferred taxes related to differences between the bases of assets and liabilities for financial and income tax reporting. Deferred tax assets and liabilities represent the future tax consequences of those differences, which will either be taxable or deductible when the assets and liabilities are recovered or settled. Valuation allowances are recognized to limit recognition of deferred tax assets where appropriate. Such allowances may be reversed when circumstances provide evidence that the deferred tax assets will more likely than not be realized.

Production Taxes and Ad Valorem Taxes

Production taxes and ad valorem taxes are included in production expense. Total production and ad valorem taxes were $1,194,443 and $1,297,165 for the years ended December 31, 2013 and 2012, respectively.

Use of Estimates and Certain Significant Estimates

The preparation of the Company's financial statements in conformity with accounting principles generally accepted in the United States of America requires the Company's management to make estimates and assumptions that affect the amounts reported in these financial statements and accompanying notes. Actual results could differ from those estimates. Significant assumptions are required in the valuation of proved oil and natural gas reserves, which as described above may affect the amount at which oil and natural gas properties are recorded. The Company's allowance for doubtful accounts is a significant estimate and is based on management's estimates of uncollectible receivables. The asset retirement obligations require estimates of future plugging and abandonment expenditures. It is at least reasonably possible these estimates could be revised in the near term and the revisions could be material.

Our estimates of proved reserves materially impact depletion and impairment expense. If proved reserves decline, then the rate at which we record depletion expense increases, reducing net income. A decline in estimates of proved reserves may result from lower prices, evaluation of additional operating history, mechanical problems at our wells and catastrophic events such as explosions, hurricanes and floods. Lower prices also may make it uneconomical to drill wells or produce from fields with high operating costs. In addition, a decline in proved reserves may impact our assessment of our oil and natural gas properties for impairment.

Our proved reserve estimates are a function of many assumptions, all of which could deviate materially from actual results. As such, reserve estimates may vary materially from the ultimate quantities of oil and natural gas actually produced.

Revenue Recognition
The Company uses the sales method of accounting for oil and natural gas revenues. Under this method, revenues are based on actual volumes of oil and natural gas sold to purchasers. The volumes of natural gas sold may differ from the volumes to which the Company is entitled based on its interest in the properties. Differences between volumes sold and volumes based on entitlements create natural gas imbalances. Material imbalances are reflected as adjustments to reported natural gas reserves and future cash flows. There were no material natural gas imbalances as of December 31, 2013 and 2012.

We recognize revenue when crude oil and natural gas quantities are delivered to or collected by the respective purchaser. Title to the produced quantities transfers to the purchaser at the time the purchaser receives or collects the quantities. Prices for such production are defined in sales contracts and are readily determinable based on certain publicly available indices. The purchasers of such production have historically made payment for crude oil and natural gas purchases within thirty-five days of the end of each production month. We periodically review the difference between the dates of production and the dates we collect payment for such production to ensure that accounts receivable from those purchasers are collectible.

As previously discussed, we sold our crude oil and natural gas production to several independent purchasers. During the year ended December 31, 2013, we had sales of 10% or more of our total oil and natural gas sales revenue to two customers which represented 71% of total oil and natural gas sales revenue for the year ended December 31, 2013. During the year ended December 31, 2012, we had sales of 10% or more of our total oil and natural gas sales revenue to four customers which represented 64% of total oil and natural gas sales revenue for the year ended December 31, 2012.

Comprehensive Income
The Company has no elements of comprehensive income other than net income.

Share-Based Compensation
We measure and record compensation expense for all share-based payment awards to employees and directors based on estimated fair values. Additionally, compensation costs for share-based awards are recognized over the requisite grant-date service period based on the grant-date fair value. There were no outstanding share-based awards during 2013 or 2012.

Financial Instruments
The Company's financial instruments are cash, certificates of deposit, accounts receivable and payable and long-term debt. Management believes the fair values of these instruments, with the exception of the long-term debt, approximate the carrying values, due to the short-term nature of the instruments. Management believes the fair value of long-term debt also reasonably approximates its carrying value, based on expected cash flows and interest rates.

2. OIL AND NATURAL GAS PROPERTIES

The Company made no purchases of oil and natural gas properties during the years ended December 31, 2013 and 2012. The Company drilled a successful developmental well in New Mexico in 2013, for which the net cost to the Company was approximately $3,000,000. The Company also drilled a successful developmental well in New Mexico in 2012, for which the net cost to the Company was approximately $3,000,000.

The Company sold its interest in the Stauss Field in October 2013 for net proceeds of $5,000. A gain of $4,000 was recognized on the sale as the property had been previously impaired. The Company sold its interest in the South Vacuum Field in October 2012 for net proceeds of $204,000. A gain of $204,000 was recognized in 2012 on the sale as the property had been fully impaired.

The Irby #1 on the Riverdale Prospect in Goliad County, Texas, was drilled and deemed to be non-economic after analyzing the electric logs. The decision was made to plug and abandon the well and no other exploratory wells are planned for this prospect. Dry hole expenses of $152,650 were recognized for the twelve months ending December 31, 2013. No dry hole expenses were recognized in 2012.

3. RELATED PARTY TRANSACTIONS

The Company leases office space from the estate of its former president. Rent expense for this month-to-month lease was $30,000 for each of the years ended December 31, 2013 and 2012, respectively.

4. COMMODITY DERIVATIVES

On September 26, 2013, we entered into the following commodity positions to hedge our oil production price risk, through March 31, 2014. The following positions were outstanding at December 31, 2013:

Period	Volume (Barrels)		$/Barrel	
	Daily	Total	Floor	Ceiling
NYMEX –WTI Collars Jan – March 2014	200	18,000	$87.00	$108.00

The following table summarizes the fair value of our open commodity derivatives as of December 31, 2013 and 2012:

	Liability Derivatives		
		Fair Value	
	Balance Sheet Location	December 31, 2013	December 31, 2012
Derivatives not designated as hedging instruments			
Commodity derivatives	Current Liabilities	$ 4,000	$ -

The following table summarizes the change in fair value of our commodity derivatives:

		12 Months Ended December 31,	
	Income Statement Location	2013	2012
Derivatives not designated as hedging instruments			
Unrealized loss on commodity derivatives	Other Income (Expense)	$ (4,000)	$ -
Realized gain on commodity derivatives	Other Income (Expense)	$ -	$ 254,151

Unrealized gains and losses, at fair value, are included on our consolidated balance sheets as current or non-current assets or liabilities based on the anticipated timing of cash settlements under the related contracts. Changes in the fair value of our commodity derivative contracts are recorded in earnings as they occur and included in other income (expense) on our consolidated statements of operations. We estimate the fair values of collar contracts based on the present value of the difference in exchange-quoted forward price curves and contractual settlement prices multiplied by notional quantities. We internally valued the option contracts using industry-standard option pricing models and observable market inputs. We use our internal valuations to determine the fair values of the contracts that are reflected on our consolidated balance sheets. Realized gains and losses are also included in other income (expense) on our consolidated statements of operations.

We are exposed to credit losses in the event of non-performance by the counterparties on our commodity derivatives positions and have considered the exposure in our internal valuations. However, we do not anticipate non-performance by the counterparties over the term of the commodity derivatives positions. To estimate the fair value of our commodity derivatives positions, we use market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the market approach for recurring fair value measurements and attempt to use the best available information. We determine the fair value based upon the hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and lowest priority to unobservable inputs (Level 3 measurement). The three levels of fair value hierarchy are as follows:

- Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. At December 31, 2013, we had no Level 1 measurements

- Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Our derivatives, which consist of commodity collars, are valued using commodity market data which is derived by combining raw inputs and quantitative models and processes to generate forward curves. Where observable inputs are available, directly or indirectly, for substantially the full term of the asset or liability, the instrument is categorized in Level 2. At December 31, 2013, all of our commodity derivatives were valued using Level 2 measurements.

- Level 3 – Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. At December 31, 2013, we had no Level 3 measurements.

Realized gains and losses are included in other income (expense) on our consolidated statements of operations. No realized gains were recognized for the year ending December 31, 2013. Realized gains were $254,151 for the year ending December 31, 2012.

5. LINE OF CREDIT

The Company has a line of credit with a bank with a borrowing base of $11,000,000 at December 31, 2013 and 2012, respectively. The amount outstanding under this line of credit was $6,740,000 as of December 31, 2013 and 2012. The agreement requires monthly interest-only payments until maturity on October 18, 2016. The interest rate is based on a LIBOR or Prime option. The Prime option provides for the interest rate to be prime plus a margin ranging between 1.75% and 2.25% and the LIBOR option to be the 3-month LIBOR rate plus a margin ranging between 2.75% and 3.25%, both depending on the borrowing base usage. Currently, we have elected the LIBOR interest rate option in which our interest rate was approximately 3.50% as of December 31, 2013 and 2012, respectively. The commitment fee is .50% of the unused borrowing base. The line of credit provides for certain financial covenants and ratios which include a current ratio, leverage ratio, and interest coverage ratio requirements. We were in compliance with our covenants as of December 31, 2013 and 2012. The credit line was amended on March 19, 2014 on the substantially identical terms, except that the requirement for a personal guarantee by the President and CEO was removed, and extended the maturity date to October 18, 2016.

6. INCOME TAXES

Our provision for income taxes comprised the following (expense) benefit during the years ended December 31:

	2013	2012
Current:		
Federal	$ (109,000)	$ (248,000)
State	(20,070)	(64,000)
Total current	(129,070)	(312,000)
Deferred:		
Federal	(590,000)	(842,000)
State	(48,000)	(20,000)
Total deferred	(638,000)	(862,000)
Total income tax provision	$ (767,070)	$ (1,174,000)

Total income tax (expense) benefit differed from the amounts computed by applying the U.S. Federal statutory tax rates and estimated state rates to pre-tax income for the years ended December 31, 2013 and 2012 as follows:

	2013	2012
Statutory rate	34%	34%
State taxes, net of federal benefit	3%	2%
Effective rate	37%	36%

Deferred tax assets and liabilities are the result of temporary differences between the financial statement carrying values and tax bases of assets and liabilities.

Significant components of net deferred tax assets and liabilities are:

	December 31,	
	2013	2012
Deferred tax assets:		
Asset retirement obligation	$ 393,000	$ 357,000
Allowance for doubtful accounts	63,000	63,000
Accrued compensation and other	-	109,000
Unrealized loss on commodity derivatives	1,000	-
Alternative minimum tax credit carryforward	80,000	-
Total deferred tax assets	537,000	529,000
Deferred tax liability:		
Difference in depreciation, depletion and capitalization methods – oil and gas properties	(3,446,000)	(2,800,000)
Total deferred tax liabilities	(3,446,000)	(2,800,000)
Net deferred tax liability	$ (2,909,000)	$ (2,271,000)

Our net deferred tax assets and liabilities are recorded as follows:

	2013	2012
Current asset	$ 64,000	$ 171,000
Non-current liability	(2,973,000)	(2,442,000)
Total	$ (2,909,000)	$ (2,271,000)

The Company had no material uncertain tax positions as of December 31, 2013 and 2012.

The Company's policy regarding income tax interest and penalties is to record those items as general and administrative expense. During the years ended December 31, 2013 and 2012, there were no significant income tax interest and penalty items in the income statement, nor as a liability on the balance sheet at December 31, 2013 and 2012.

The Company files income tax returns in the U.S. federal jurisdiction and various state jurisdictions. Generally, the Company is no longer subject to U.S. federal or state income tax examination by tax authorities for years before 2010. The Company is not currently involved in any income tax examinations.

7. EARNINGS PER SHARE

Basic earnings per share are computed based on the weighted average number of shares of common stock outstanding during the year. Diluted earnings per share take common stock equivalents (such as options and warrants) into consideration using the treasury stock method. The Company distributed warrants as a dividend to stockholders as of the record date, March 23, 2012. The dilutive effect of the warrants for the twelve months ended December 31, 2013 and 2012 is presented below.

	December 31,	
	2013	2012
Net income	$ 1,278,997	$ 2,112,263
Weighted average common stock outstanding	8,062,167	8,006,959
Weighted average dilutive effect of stock warrants	323,086	445,470
Dilutive weighted average shares	8,385,253	8,452,429
Earnings per share:		
Basic	$ 0.16	$ 0.26
Diluted	$ 0.15	$ 0.25

8. STOCKHOLDERS' EQUITY

We approved a stock warrant dividend of one warrant per one common share outstanding in the fourth quarter of 2011 with the record date of March 23, 2012. A total of 7,983,175 warrants were issued and have an exercise price of $4.00. The warrants are exercisable over 6 years from the record date. The Company has the right to call the warrants in the future if the market price of the common stock exceeds 150% of the exercise price of the warrant ($6.00). The fair value of the warrants of approximately $8,000,000 was reclassified from retained earnings to additional paid in capital to the extent of available retained earnings of $6,895,361 on the record date. A total of 22,400 warrants to purchase an equal number of common shares for proceeds of $89,600 were exercised during the year ended December 31, 2013. The following table summarizes the warrants outstanding at December 31, 2012 and December 31, 2013:

Warrants outstanding, December 31, 2012	7,983,175
Warrants exercised	(22,400)
Warrants outstanding, December 31, 2013	7,960,775

Effective May 16, 2012, we executed an At Market Issuance Sales Agreement with MLV & Co., LLC ("MLV") providing for an at-the-market offering of securities of up to 900,000 shares of common stock (the "ATM Offering"). The ATM Offering was undertaken pursuant to Rule 415 and a universal shelf Registration Statement on Form S-3 which was declared effective by the SEC on December 9, 2011. We paid a sales commission equal to 7% of the gross sales price per share sold in addition to other costs to register the securities. Effective June 25, 2012 to December 31, 2012, we sold through MLV 60,761shares of common stock pursuant to this agreement for gross proceeds of $257,358. Expenses associated with the sale of common shares were $63,769 which includes commissions and other offering costs. No shares were sold in the year ended December 31, 2013. The Board of Directors terminated the ATM Offering in February, 2014.

9. ENVIRONMENTAL ISSUES

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

10. COMMITMENTS

As of December 31, 2013 and 2012, we had a $30,000 outstanding standby letter of credit in favor of the State of Wyoming as a plugging bond. The letter of credit is collateralized by our line of credit with Citibank.

On November 12, 2013, we engaged Stephens, Inc. ("Stephens") to provide general financial and Investment Banking advice. Pursuant to the agreement we began paying Stephens a retainer of $10,000 per month, paid monthly in advance beginning January 1, 2014. The agreement can be terminated by either party with thirty days' notice with no further obligation for a monthly retainer. The agreement provides for success fees in the range of 1% to 7% depending on the nature of the transaction. Furthermore, any amounts paid for the retainer would be credited against any investment banking fees due in the event of a successful transaction.

On October 24, 2008, our Board of Directors approved a Performance Based Bonus Program (the "Bonus Program") for our President and Chief Executive Officer. The Bonus Program is calculated and paid annually based on four performance parameters: 1) annual reserve additions from drilling and acquisitions; 2) growth in annual production; 3) growth in annual year over year earnings (before taxes and bonus); and 4) other notable achievements as the Board may recognize from time to time which are not easily quantifiable in the first three parameters. Bonus awards of up to 50% of annual base salary may be achieved in each of the first three categories and up to 10% in the fourth category provided that the maximum bonus award for any year may not exceed 150% of base salary which is currently $280,000. No bonuses were awarded under the Bonus Program in 2013. The Bonus Program is no longer in effect due to the death of our former President, Ray Reaves. We awarded approximately $300,000 to our former President and Chief Executive Officer, Ray Reaves, under the Bonus Program in 2012.

11. SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

The following table sets forth certain information with respect to the oil and natural gas producing activities of the Company:

	Years Ended December 31,	
	2012	2011
Costs incurred in oil and natural gas producing activities:		
Acquisition of unproved properties	$ -	$ -
Acquisition of proved properties	-	-
Exploration costs	152,650	-
Development costs	3,479,135	4,571,324
Total costs incurred	$ 3,631,785	$ 4,571,324

The following table summarizes changes in the estimates of the Company's net interest in total proved reserves of crude oil and condensate and natural gas and liquids, all of which are domestic reserves. There can be no assurance that such estimates will not be materially revised in subsequent periods.

	Oil (Barrels)	Gas (MCF)
Balance, January 1, 2012	1,200,264	2,269,548
Revisions of previous estimates	13,854	48,955
Extensions and discoveries	115,093	209,930
Sale of reserves	-	-
Purchase of minerals in place	-	-
Production	(104,285)	(180,098)
Balance, December 31, 2012	1,224,926	2,348,335
Revisions of previous estimates	(202,450)	(322,413)
Extensions and discoveries	99,988	143,343
Sale of reserves	-	-
Purchase of minerals in place	-	-
Production	(101,752)	(179,737)
Balance, December 31, 2013	1,020,712	1,989,528
Proved developed reserves, December 31, 2013	916,139	1,834,899
Proved developed reserves, December 31, 2012	983,900	1,898,705

Proved oil and natural gas reserves are the estimated quantities of crude oil, condensate, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and natural gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. The above estimated net interests in proved reserves are based upon subjective engineering judgments and may be affected by the limitations inherent in such estimation. The process of estimating reserves is subject to continual revision as additional information becomes available as a result of drilling, testing, reservoir studies and production history, and market prices for oil and natural gas. Significant fluctuations in market prices have a direct impact on recoverability and will result in changes in estimated recoverable reserves without regard to actual increases or decreases in reserves in place.

Year Ended December 31, 2012

The average natural gas price used in our proved reserves estimate at December 31, 2012 was $2.60 per Mcf. The average oil price used in our proved reserves estimate at December 31, 2012 was $93.42 per barrel. We re-completed additional wells on the Apache Bromide lease during the year end 2012, and we drilled the East Lusk Federal well #2, which were the primary reasons for the quantities listed under extensions and discoveries.

Year Ended December 31, 2013

The average natural gas price used in our proved reserves estimate at December 31, 2013 was $3.49 per Mcf. The average oil price used in our proved reserves estimate at December 31, 2013 was $90.14 per barrel. We drilled the East Lusk Federal well #3 and re-completed an additional well on the North Block lease during the year ended December 31, 2013, which were the primary reasons for the quantities listed under extensions and discoveries. Our consulting engineers decreased our proved reserves in the East Lusk Field due to a steeper than anticipated decline curve on the East Lusk Federal #2 and #3 wells.

12. STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS (UNAUDITED)

The standardized measure of discounted future net cash flows at December 31, 2013 and 2012, relating to proved oil and natural gas reserves is set forth below. The assumptions used to compute the standardized measure are those prescribed by the Financial Accounting Standards Board and, as such, do not necessarily reflect our expectations of actual revenues to be derived from those reserves nor their present worth. The limitations inherent in the reserve quantity estimation process are equally applicable to the standardized measure computations since these estimates are the basis for the valuation process.

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves and the changes in standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves were prepared in accordance with prescribed accounting and SEC standards. Future cash inflows were computed by applying the unweighted, arithmetic average of the closing price on the first day of each month for the 12-month period prior to December 31, 2013 and 2012, to estimated future production. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and natural gas reserves at year end, based on year-end costs and assuming continuation of existing economic conditions.

Future income tax expenses are calculated by applying appropriate year-end tax rates to future pre-tax net cash flows relating to proved oil and natural gas reserves, less the tax basis of properties involved.

Future income tax expenses give effect to permanent differences, tax credits and loss carryforwards relating to the proved oil and natural gas reserves. Future net cash flows are discounted at a rate of 10% annually to derive the standardized measure of discounted future net cash flows. This calculation procedure does not necessarily result in an estimate of the fair market value of our oil and natural gas properties.

	Years Ended December 31, (in thousands)	
	2013	2012
Future cash inflows	$ 101,289	$ 117,560
Future production costs	(38,667)	(43,641)
Future development cost	(3,681)	(5,022)
Future income taxes	(18,115)	(21,200)
Future net cash flows	40,826	47,697
10% annual discount	(20,455)	(22,597)
Standardized measure of discounted future net cash flows	$ 20,371	$ 25,100

The following are the principal sources of change in the standardized measure of discounted future net cash flows, in thousands:

	Years Ended December 31, 2013	Years Ended December 31, 2012
Balance, beginning of year	$ 25,100	$ 25,913
Sales of oil and natural gas produced, net of production costs	(6,416)	(6,914)
Sale of reserves	-	-
Extensions and discoveries	3,040	3,722
Net changes in prices and production costs	525	(2,400)
Net changes in future development costs	(1,227)	(2,160)
Revisions and other changes	(6,556)	2,861
Accretion of discount	3,736	3,841
Net change in income taxes	2,169	237
Balance, end of year	$ 20,371	$ 25,100

13. SUBSEQUENT EVENT (UNAUDITED)

Subsequent to December 31, 2013, the Company participated in a successful development well in the Taylor Serbin field, for which the net cost was approximately $1,000,000. We drew $500,000 from our line of credit to finance approximately half of the costs of this well. Production on the well began in late January 2014.

As of February 1, 2014, the Company no longer rents office space from the estate of our former President, Ray Reaves. On January 24, 2014, the Company entered into a two year lease for office space in Austin, Texas, for approximately $3,000 per month.

In January 2014, the Company entered into a consulting agreement with a relative of a Board member for petroleum engineering services related to our oil and natural gas properties. Services rendered under this agreement were $28,000 in January to March, 2014.

On January 1, 2014 FieldPoint Petroleum Corp. ("FieldPoint") signed an exploration agreement ("the agreement") with Riley Exploration, LLC ("Riley"). The agreement provides for an Area of Mutual Interest ("AMI") and a 90 day due diligence period, after which both Companies will cross assign their working interest and vertical wells with a targeted ownership for FieldPoint of 25%. The agreement also provides for a development plan with the intent to drill up to twelve horizontal wells during the initial twelve month period after closing. FieldPoint may elect to be the drilling operator of every fifth well. The agreement also provides for a standard Joint Operating Agreement which allows either partner to participate or decline to participate in every well with no obligatory wells.

* * * * * * *

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

a) Our Principal Executive Officer, Roger D. Bryant, and our Principal Financial Officer, Phillip H. Roberson, have established and are currently maintaining disclosure controls and procedures for the Company. The disclosure controls and procedures have been designed to provide reasonable assurance that the information required to be disclosed by the Company in reports that it files under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and to ensure that information required to be disclosed by the Company is accumulated and communicated to the Company's management as appropriate to allow timely decisions regarding required disclosure.

Our former Principal Executive Officer and Principal Financial Officer, Ray D. Reaves, passed away on June 6, 2013. As a result, on June 9, 2013 the Board of Directors appointed Roger D. Bryant to serve as the Executive Chairman of the Board of Directors and oversee management of the Company. On June 14, 2013, Mr. Phillip H. Roberson was engaged to take operational control of the business, and on July 1, 2013, he was named Chief Operating Officer and Chief Financial Officer. On December 10, 2013, Mr. Roberson was promoted to President of the Company.

The Principal Executive Officer and Principal Financial Officer conducted a review and evaluation of the effectiveness of the Company's disclosure controls and procedures and have concluded, based on their evaluation as of the end of the period covered by this Report, that our disclosure controls and procedures are effective to provide reasonable assurance that information required to be disclosed in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Commission’s rules and forms and to ensure that the information required to be disclosed by the Company is accumulated and communicated to management, including our principal executive officer and our principal financial officer, to allow timely decisions regarding required disclosure.

b) There has been no change in our internal control over financial reporting during the fourth quarter ended December 31, 2013 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Our principal executive and financial officer do not expect that our disclosure controls or internal controls will prevent all error and all fraud. Although our disclosure controls and procedures were designed to provide reasonable assurance of achieving their objectives and our principal executive and financial officer have determined that our disclosure controls and procedures are effective at doing so, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute assurance that the objectives of the system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs.

Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented if there exists in an individual a desire to do so. There can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. Internal control over financial reporting refers to the process designed by, or under the supervision of, our Principal Executive Officer and Principal Financial Officer, and effected by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, and includes those policies and procedures that:

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

2) Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and,

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. 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.

Management has used the framework set forth in the report entitled "Internal Control – Integrated Framework" published by the Committee of Sponsoring Organizations of the Treadway Commission to evaluate the effectiveness of the Company's internal control over financial reporting. Management has concluded that the Company's internal control over financial reporting was effective as of the end of the most recent fiscal year.

This annual report does not include an attestation report of the Company's independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by the Company's independent registered public accounting firm pursuant to rules of the Securities and Exchange Commission that permit the Company to provide only management's report in this Form 10-K.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10 DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

(a) Identification of Directors and Executive Officers. The following table sets forth the names and ages of the Directors and Executive Officers of the Company, all positions and offices with the Company held by such person, and the time during which each such person has served:

Name	Age	Position with Company	Period Served
Roger D. Bryant	71	Principal Executive Officer, Director,	June 9, 2013-present July 1997-present
Phillip H. Roberson	45	President, Principal Financial Officer	December 2013-present July 2013-present
Ray D. Reaves	51	Director, President, Chairman, Principal Executive Officer	May 1997-June 6, 2013
Karl W. Reimers	72	Director	October 2004-present
Dan Robinson	66	Director	August 2004-present
Debra Funderburg	55	Director	February 2006 - present
Nancy Stephenson	60	Director	October 2012 - present

Mr. Reaves was Chairman, Director, President, Chief Executive Officer and Chief Financial Officer of the Company from May 22, 1997 until his death, June 6, 2013. Mr. Reaves also served as Chairman, Chief Executive Officer, Chief Financial Officer and Director of Bass Petroleum, Inc. from October 1989 to his death, has 25 years experience in the oil and natural gas industry. He began his career in 1987, with North American Oil and Gas. Subsequently, in 1989 he purchased an interest in 10 of their wells and formed Bass Petroleum, Inc. Under Mr. Reaves' management in the years that followed, Bass Petroleum, Inc. gained majority control of the 10 original wells and acquired interest in another 60 wells. In 1998, Bass Petroleum merged with Energy Production Corporation and as a result, FieldPoint Petroleum Corporation was born.

Mr. Bryant serves as Chairman of the Board of the Corporation, and as its principal executive. He has been a Director of the Company since July 1997. For more than twenty-five years, Mr. Bryant has held senior management positions with public and private companies in a number of different industries. He is currently a Founder and Partner of Co-Partners, LLC, a business consulting firm. Prior positions include Chief Executive Officer and Chairman of Canmax, Inc., a publicly traded software development company, President of Network Data Corporation, President of Dresser Industries, Inc., Wayne Division, President of Schlumberger Limited, Retail Petroleum Systems Division, U.S.A., and President of Autogas Systems, Inc., the developer of "Pay-at-the-Pump" technology for the retail petroleum industry. Mr.

Bryant holds a Bachelor of Science degree in Electrical Engineering from the University of Alabama, and has served on the Board of Directors of more than ten private and public companies.

Mr. Roberson, age 45, was engaged to take operational control of the business on June 14, 2013. He was named Principal Operating Officer and Principal Financial Officer on July 1, 2013. Prior to joining FieldPoint, he was founder of AEG Operating LLC, an independent oil and gas exploration company, where he was instrumental in the funding, acquisition and day to operations of the firm's operated and non-operated properties. Previously, he served as a director of Energy Investment Banking with Tejas Securities, Inc. where he assisted Exploration & Production and Energy Service companies with debt & equity offerings. Until it was acquired by Tejas Securities, Mr. Roberson was an Equity Analyst with Arabella Securities, LLC, covering Energy and Special Situation companies. Mr. Roberson received a Bachelor of Business Administration in Finance from the University of Texas at Austin and is a licensed Certified Public Accountant.

Mr. Reimers, age 72, is a CPA and has served as a director of the Company since October 2004. Mr. Reimers has held the position of President and CFO of B.A.G. Corp. from 1993 until his retirement in 2010. He served as Vice President and CFO of Supreme Beef Company from 1989 to 1993. He also held the position of Vice President of Accounting at OKC Corp., a NYSE listed oil and gas company from 1975 to 1989. He was employed by Peat, Marwick, Mitchell, Certified Public Accountants, from 1973 to 1975, and he holds an MBA from the University of Texas at Arlington.

Mr. Robinson, age 66, has served as a director of the Company since August 2004. He has held the position of President and Chief Executive Officer of Placid Refining Company LLC from December 2004 to the present. Prior to his current position, he served in many capacities with Placid Oil Company beginning in March 1975, including the roles of Project Engineer, Manager of Refinery Operations, Assistant Secretary, Assistant Treasurer, Secretary, and Treasurer. Before beginning his 30 year oil and gas career he was briefly employed as a commercial credit analyst at First National Bank in Dallas. Mr. Robinson received a BS degree in Mechanical Engineering in 1971 and an MBA degree in Finance in 1973, both from the University of Wisconsin. He currently sits on the Board of Directors of the National Petrochemical and Refiners Association.

Debra Funderburg, age 55, has been a director of the Company since February 6, 2006. From August 2010 to present she has served as Vice President Reservoir Engineering for Magnum Hunter Resources Corp. From September 2007 to August 2010 she served as Vice President of Business Development for Sanchez Oil & Gas. From May 2003 to August 2007 she has served as Senior Reservoir Engineer, Corporate A&D coordinator and Business Development manager for Dominion E&P. From November 1999 to May 2003 Ms. Funderburg held the position of Reservoir Engineering Manager for Randall & Dewey. From April 1993 to November 1999 she was employed by Pennzoil as a Senior Petroleum Engineer.

Nancy Stephenson, age 60, has been a director of the Company since October 1, 2012. Ms. Stephenson was the Chief Accounting Officer for Cross Border Resources Corp. from August 10, 2011 through July 31, 2012 when she resigned as an officer but remained on staff through August 31, 2012. Ms. Stephenson has over 30 years of accounting experience, primarily in publicly traded companies in the energy business. From March 2003 to February 2010, she served as Compliance Reporting Manager for TXCO Resources Inc. As Compliance Reporting Manager, she assisted with the preparation of financial statements and was responsible for TXCO Resources, Inc.'s periodic reporting compliance with the SEC. Since March 2010, she has provided consulting services relating to periodic reporting with the SEC on a project basis for various companies. Ms. Stephenson holds a BBA in Accounting from the University of Houston and is a Certified Public Accountant.

No family relationship exists between any director or executive officer.

There are no material proceedings to which any director, officer or affiliate of the Company, any owner of record or beneficially of more than five percent (5%) of any class of voting securities of the Company, or any associate of any such director, officer, affiliate of the Company, or security holder is a party adverse to the Company or any of its subsidiaries or has a material interest adverse to the Company or any of its subsidiaries.

During the last ten (10) years no director or officer of the Company has:

a. had any bankruptcy petition filed by or against any business of which such person was a general partner or executive officer either at the time of the bankruptcy or within two years prior to that time;

b. been convicted in a criminal proceeding or subject to a pending criminal proceeding;

c. been subject to any order, judgment, or decree, not subsequently reversed, suspended or vacated, of any court of competent jurisdiction, permanently or temporarily enjoining, barring, suspending or otherwise limiting his involvement in any type of business, securities or banking activities; or

d. been found by a court of competent jurisdiction in a civil action, the Commission or the Commodity Futures Trading Commission to have violated a federal or state securities or commodities law, and the judgment has not been reversed, suspended, or vacated.

Any transactions between the Company and its officers, directors, principal shareholders, or other affiliates have been and will be on terms no less favorable to the Company than the Board of Directors believes could be obtained from unaffiliated third parties on an arms-length basis and will be approved by a majority of the Company's independent, outside disinterested directors.

Meetings and Committees of the Board of Directors

a**.** Meetings of the Board of Directors

During the fiscal year ended December 31, 2013, eight meetings of the Board of Directors were held, including regularly scheduled and special meetings, each of which were attended by all of the directors with the exception of the November 18, 2013, meting, which did not include Karl Reimers as he was traveling outside of the country. Meetings are conducted either in person or by telephone conference.

In 2013, outside directors received $500 per in-person meeting and were reimbursed their expenses associated with attendance at such meetings or otherwise incurred in connection with the discharge of their duties as a director. As compensation for the increased activity levels since the untimely death of our CEO, the Chairman of the Board of Directors received a onetime fee of $35,000 and outside directors received $25,000 each in onetime fees for the fiscal year ended December 31, 2013. In addition, Roger Bryant was paid $6,000 per month for his role as Executive Chairman. Directors could receive grants of options to purchase shares of common stock. Ms. Funderburg and Ms. Stephenson each received a $12,000 annual retainer. At the December 6, 2013, meeting, the Board approved the Compensation Committee's recommendation to restructure Board compensation effective for 2014. The new structure increases the fee for in-person meetings to $1,000 and provides for fees to compensate committee chairmen. It is expected that each member will receive approximately $39,000 for their service during 2014. Roger Bryant will be paid $10,000 per month plus meeting fees as Executive Chairman.

b**.** Committees

The Board appoints committees to help carry out its duties. In particular, Board committees work on key issues in greater detail than would be possible at full Board meetings. Each committee reviews the result of its meetings with the full Board.

During the year ended December 31, 2013, the Board had a standing Audit Committee, a standing Compensation Committee, and a standing Nomination Committee.

Audit Committee

The Audit Committee was composed of the following directors:

Nancy Stephenson, Chairperson
Karl W. Reimers
Dan Robinson

The Board of Directors has determined that Messrs. Reimers, Robinson, and Ms. Stephenson are "independent" within the meaning of the NYSE MKT, LLC's listing standards and Item 407(a) of Regulation S-K. For this purpose, an Audit Committee member is deemed to be independent if he or she does not possess any vested interests related to those of management and does not have any financial, family or other material personal ties to management. On April 2, 2013 Nancy Stephenson replaced Karl Reimers as Chairperson. Roger Bryant served on the Audit Committee prior to his election as Executive Chairman of the Board on June 9, 2013, when he was no longer considered independent while serving as Executive Chairman. Karl Reimers and Nancy Stephenson, each a member of the Audit Committee, qualify as an "audit committee financial expert" within the meaning of Item 407(d)(5) of Regulation S-K.

During the fiscal year ended December 31, 2013 the Audit Committee had four meetings. The committee is responsible for accounting and internal control matters. The Audit Committee:

- reviews with management, the external consultants and the independent auditors policies and procedures with respect to internal controls;

- reviews significant accounting matters;

- approves any significant changes in accounting principles of financial reporting practices;

- reviews independent auditor services; and

- recommends to the Board of Directors the firm of independent auditors to audit our consolidated financial statements.

In addition to its regular activities, the committee is available to meet with the independent accountants, external consultants whenever a special situation arises.

The Audit Committee of the Board of Directors has adopted a written charter, which has been previously filed with the Commission.

Audit Committee Report

The Audit Committee has reviewed and discussed the audited financial statements with management and with Hein & Associates LLP and the matters required to be discussed by AU Section 380. The Audit Committee has received the written disclosures and the letter from Hein & Associates LLP required by Independence Standards Board Standard No. 1 and has discussed with them their independence. Based on the review and discussions referred to above, the Audit Committee has recommended to the Board of Directors that the audited financial statements be included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2013 for filing with the Commission.

By the Audit Committee
Nancy Stephenson
Karl Reimers
Dan Robinson

Compensation Advisory Committee

The Compensation Advisory Committee is currently composed of the following directors:

Dan Robinson, Chairman
Karl Reimers
Debbie Funderburg

The Board of Directors has determined that Messrs. Robinson, Reimers and Funderburg are "independent" within the meaning of the NYSE MKT, LLC's listing standards and Item 407(a) of Regulation S-K. For this purpose, a Compensation Committee member is deemed to be independent if he does not possess any vested interests related to those of management and does not have any financial, family or other material personal ties to management.

During the fiscal year ended December 31, 2013 the Compensation Advisory Committee had two meetings. The Compensation Advisory Committee:

- Recommends to the Board of Directors the compensation and cash bonus opportunities based on the achievement of objectives set by the Compensation Advisory Committee with respect to our Chairman of the Board and President, our Chief Executive Officer and the other executive officers;

- administers our compensation plans for the same executives;
- determines equity compensation for all employees;
- reviews and approves the cash compensation and bonus objectives for the executive officers; and
- reviews various matters relating to employee compensation and benefits.

Nomination Committee

The Nomination Committee was composed of the following directors:

Karl Reimers, Chairman
Debbie Funderburg

Of the currently serving two members Messrs. Reimers and Funderburg, would each be deemed to be independent within the meaning of the NYSE MKT, LLC's listing standards and Item 407(a) of Regulation S-K. For this purpose, a director is deemed to be independent if he does not possess any vested interests related to those of management and does not have any financial, family or other material personal ties to management. The committee had one meeting in 2013. Roger Bryant resigned from the Nomination Committee in 2013 as he was no longer considered independent while serving as Executive Chairman and not yet been replaced.

The Board of Directors has not adopted a policy with regard to the consideration of any director candidates recommended by security holders, since to date the Board has not received from any security holder a director nominee recommendation. The Board of Directors will consider candidates recommended by security holders in the future. Security holders wishing to recommended a director nominee for consideration should contact Mr. Phillip H. Roberson, President, Chief Operating Officer and Chief Financial Officer, at the Company's principal executive offices located in Austin, Texas and provide to Mr. Roberson, in writing, the recommended director nominee's professional resume covering all activities during the past five years, the information required by Item 401 of Regulation S-X, and a statement of the reasons why the security holder is making the recommendation. Such recommendation must be received by the Company before December 31, 2013.

The Board of Directors believes that any director nominee must possess significant experience in business and/or financial matters as well as a particular interest in the Company's activities.

All director nominees identified in this proxy statement were recommended by our President and Chief Financial Officer and unanimously approved by the Board of Directors.

Shareholder Communications

Any shareholder of the Company wishing to communicate to the Board of Directors may do so by sending written communication to the Board of Directors to the attention of Mr. Roger Bryant, Principal Executive Officer, or Mr. Phillip Roberson, Chief Financial Officer, at the principal executive offices of the Company. The Board of Directors will consider any such written communication at its next regularly scheduled meeting.

Any transactions between the Company and its officers, directors, principal shareholders, or other affiliates have been and will be on terms no less favorable to the Company than could be obtained from unaffiliated third parties on an arms-length basis and will be approved by a majority of the Company's independent, outside disinterested directors.

Code of Ethics

Our Board of Directors adopted a Code of Business Conduct and Ethics for all of our directors, officers and employees during the fiscal year ended December 31, 2003. Our Code of Business Conduct and Ethics can be found at our website address: http://www.fppcorp.com. We will provide to any person without charge, upon request, a copy of our Code of Business Conduct and Ethics. Such request should be made in writing and addressed to Investor Relations, FieldPoint Petroleum Corporation, 609 Castle Ridge Road, Suite 335, Austin, Texas 78746. Further, our Code of Business Conduct and Ethics is filed as an exhibit to the Company's Annual Report on Form 10-KSB for the fiscal year ending December 31, 2003.

COMPLIANCE WITH SECTION 16(a) OF THE SECURITIES EXCHANGE ACT

Section 16 (a) of the Securities Exchange Act of 1934, as amended, requires the Company's executive officers, directors and persons who own more than ten percent of the Common Stock (collectively, "Reporting Persons") to file initial reports of ownership and changes of ownership of the Common Stock with the SEC and the NYSE Amex. Reporting Persons are required to furnish the Company with copies of all forms that they file under Section 16(a). Based solely upon our search of publicly available information or information provided to the Company from Reporting Persons, during the two years ended December 31, 2013, the Company is not aware of any failure on the part of any Reporting Persons to timely file reports required pursuant to Section 16(a).

ITEM 11 EXECUTIVE COMPENSATION

COMPENSATION DISCUSSION AND ANALYSIS

Introduction. This Compensation Discussion and Analysis ("CD&A") provides an overview of the Company's executive compensation program together with a description of the material factors underlying the decisions which resulted in the compensation provided for 2013 to the Company's "Named Executive Officers" (or "NEOs"), as presented in the tables which follow this CD&A. The following discussion and analysis contains statements regarding future individual and Company performance targets and goals. These targets and goals are disclosed in the limited context of the Company's compensation programs and should not be understood to be statements of management's expectations or estimates of financial results or other guidance. The Company specifically cautions investors not to apply these statements to other contexts.

Compensation Committee. The Compensation Committee (the "Committee") of the Board of Directors is composed of three non-employee directors, all of whom are independent under the guidelines of the NYSE Amex listing standards. The current Committee members are Dan Robinson, Karl Reimers and

Debbie Funderburg. The Committee has responsibility for determining and implementing the Company's philosophy with respect to executive compensation. To implement this philosophy, the Committee oversees the establishment and administration of the Company's executive compensation program.

Compensation Philosophy and Objectives. The guiding principle of the Committee's executive compensation philosophy is that the executive compensation program should enable the Company to attract, retain and motivate a team of highly qualified executives who will create long-term value for the Shareholders. To achieve this objective, the Committee has developed an executive compensation program that is ownership-oriented and that rewards the attainment of specific annual, long-term and strategic goals that will result in improvement in total shareholder return. To that end, the Committee believes that the executive compensation program should include both cash and equity-based compensation that rewards specific performance. In addition, the Committee continually monitors the effectiveness of the program to ensure that the compensation provided to executives remains competitive relative to the compensation paid to executives in a peer group comprised of select container industry and other manufacturing companies. The Committee annually evaluates the components of the compensation program as well as the desired mix of compensation among these components. The Committee believes that a substantial portion of the compensation paid to the Company's NEOs should be at risk, contingent on the Company's operating and market performance. Consistent with this philosophy, the Committee will continue to place significant emphasis on stock-based compensation and performance measures, in an effort to more closely align compensation with Shareholder interests and to increase executives' focus on the Company's long-term performance.

Committee Process. The Committee meets as often as necessary to perform its duties and responsibilities. The Committee usually meets with the Executive Chairman and the President and CFO. In addition, the Committee periodically meets in executive session without management.

The Committee's meeting agenda is normally established by the Committee Chairperson in consultation with the Executive Chairman and the President and CFO. Committee members receive and review materials in advance of each meeting. Depending on the meeting's agenda, such materials may include: financial reports regarding the Company's performance, reports on achievement of individual and corporate objectives, reports detailing executives' stock ownership and options, tally sheets setting forth total compensation and information regarding the compensation programs and levels of certain peer group companies.

Role of Executive Officers in Compensation Decisions. The Committee makes all compensation decisions for the NEOs. Decisions regarding the compensation of other employees are made by the Executive Chairman and the President and CFO in consultation with the Committee. In this regard, the NEOs provide the Committee evaluations of executive performance, business goals and objectives and recommendations regarding salary levels and equity awards.

Market-Based Compensation Strategy. The Committee adopted the following market-based compensation strategy:

- Pay levels are evaluated and calibrated relative to other companies of comparable size operating in the oil and gas exploration business (the "Peer Group") as the primary market reference point. In addition, general industry data is reviewed as an additional market reference and to ensure robust competitive data.

- Target total direct compensation (target total cash compensation plus the annualized expected value of long-term incentives) levels for NEOs are calibrated relative to the Peer Group.

- Base salary and target total cash compensation levels (base salary plus target annual incentive) for NEOs are calibrated to the Peer Group.

- The long-term incentive component of the executive compensation program is discretionary and viewed in light of the target total direct compensation level.

The Committee retains discretion, however, to vary compensation above or below the targeted percentile based upon each NEO's experience, responsibilities and performance.

Total Direct Compensation

Our objective is to target total direct compensation, consisting of cash salary, cash bonus and long term equity compensation at levels consistent with the surveyed companies, if specified corporate and business unit performance metrics and individual performance objectives are met. We selected this target for compensation to remain competitive in attracting and retaining talented executives. Many of our competitors are significantly larger and have financial resources greater than our own. The competition for experienced, technically proficient executive talent in the oil and gas industry is currently particularly acute, as companies seek to draw from a limited pool of such executives to explore for and develop hydrocarbons that increasingly are in more remote areas and are technologically more difficult to access.

Components of Compensation. For the years ended December 31, 2013 and 2012, the largest component of compensation for the CEO, Executive Chairman and the President and CFO was base salary. We did provide additional compensation in the form of annual incentive bonus and perquisites to the CEO.

Base Salary. The Company provides the NEOs with base salaries to compensate them for services rendered during the year. The Committee believes that competitive salaries must be paid in order to attract and retain high quality executives. The Committee reviews the NEO's salaries at the end of each year, with any adjustments to base salary becoming effective on January 1 of the succeeding year.

In determining base salary level for executive officers, the committee considers the following qualitative and quantitative factors:

- job level and responsibilities,
- relevant experience,
- individual performance,
- recent corporate performance.

We review base salaries annually, but we do not necessarily award salary increases each year. From time to time base salaries may be adjusted other than as a result of an annual review, in order to address competitive pressures or in connection with a promotion.

Base salaries paid to the NEOs aredeductible for federal income tax purposes except to the extent that the executive's aggregate compensation which is subject to Section 162(m) of the Internal Revenue Code (the "Code") exceeds $1 million.

The following tables and discussion set forth information with respect to all plan and non-plan compensation awarded to, earned by or paid to the Company's four (4) most highly compensated executive officers, for all services rendered in all capacities to the Company and its subsidiaries for each of the Company's last three (3) completed fiscal years; provided, however, that no disclosure has been made for any executive officer, other than the CEO, whose total annual salary and bonus does not exceed $100,000.

SUMMARY COMPENSATION TABLE

Name and Principal Position	Year	Salary ($)	Bonus	Stock Awards	Options Awards	Non equity Incentive Plan Compensa -tion	Nonqualified Deferred Compensation Earnings	All Other Compensa- tion	Total
Phillip H. Roberson, President, and CFO	2013	$ 75,000	$ 35,000	-	-	-	-	-	$110,000
Ray D. Reaves, CEO, President	2013	$140,000	$ -	-	-	-	-	-	$140,000
Ray D. Reaves, CEO, President	2012	$351,400	$300,000	-	-	-	-	-	$651,400
Ray D. Reaves, CEO, President	2011	$250,000	$56,548	-	-	-	-	-	$306,548

Bonus Plan

In 2008, the Company's Board of Directors adopted a Performance Based Bonus Program for the President and CEO (the "Bonus Plan"). Under the Bonus Plan, the President can earn an annual bonus based upon four parameters: (i) annual reserve additions from drilling and acquisitions as measured by the Board approved Annual Business Plan ("Business Plan") ("Reserve Bonus"), (ii) growth in annual production as measured by the Business Plan, ("Production Bonus") (iii) growth in annual year over year earnings before taxes and bonus ("EBBT")("Earnings Bonus"), and (iv) other notable achievements as determined by the Board ("Achievement Bonus").

To earn any of the Reserve Bonus, Production Bonus or Earnings Bonus, the Company's performance must exceed the goal or target set by the Board in the Business Plan. If actual reserve additions for the year exceed the Business Plan target, a bonus will be paid equal to the percentage that the actual reserve additions bears to the total reserves reported in the previous year's Annual Report on Form 10-K (the "Prior 10-K"), not to exceed 50% of Base Salary. If actual production for the year exceeds the Business Plan target, a bonus will be paid equal to the percentage that the actual production bears to the total production reported in the Prior 10-K, not to exceed 50% of Base Salary. If actual EBBT for the year exceeds the Business Plan target, a bonus will be paid equal to the percentage that actual EBBT bears to EBBT as reported in the Prior 10-K, not to exceed 50% of Base Salary. The Achievement Bonus is discretionary with the Board and cannot exceed 10% of Base Salary. The maximum cumulative bonus payable in any given year may not exceed 150% of Base Salary. This Bonus Plan was only applicable to the former CEO Ray Reaves and no bonus was paid under the Plan in 2013.

The following table sets forth information concerning unexercised options, stock that has not vested and equity incentive plan awards for each named executive officer outstanding as of the end of the most recently completed fiscal year:

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR END TABLE

	Option Awards				**Stock Awards**				
Name	Number of Securities Underlying Unexercised Options Exercisable	Number of Securities Underlying Unexercised Options Unexercisable	Equity Incentive Plan Awards; Number of Securities Underlying Unexercised Unearned Options	Option Exercise Price	Option Exercise Date	Number of Shares or Units of Stock That Have Not Vested	Market Value of Shares of Units That Have Not Vested	Equity Incentive Plan Awards; Number of Unearned Shares, Units or Other Rights That Have Not Vested	Equity Incentive Plan Awards; Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested
Ray Reaves	- 0 -	- 0 -	-	-	-	- 0 -	-	-	-
Roger Bryant	- 0 -	- 0 -	-	-	-	- 0 -	-	-	-
Phillip Roberson	- 0 -	- 0 -	-	-	-	- 0 -	-	-	-

The following table sets forth information concerning compensation paid to the Company's directors during the most recently completed fiscal year:

DIRECTOR COMPENSATION TABLE

Name	Fees Earned or Paid in Cash	Stock Awards	Option Awards	Non-Equity Incentive Plan Compensation	Nonqualified Deferred Compensation Earnings	All Other Compensation	Total
Roger Bryant	$78,000	-	-	-	-	-	$78,000
Karl Reimers	$26,000	-	-	-	-	-	$26,000
Dan Robinson	$26,000	-	-	-	-	-	$26,000
Debra Funderburg	$37,500	-	-	-	-	-	$37,500
Nancy Stephenson	$37,500	-	-	-	-	-	$37,500

Option Grants Table

There were no stock option grants for fiscal years ended December 31, 2012 and 2013.

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

The following table sets forth information with respect to beneficial ownership of our common stock by:

* each person who beneficially owns more than 5% of the common stock;
* each of our executive officers named in the Management section;
* each of our directors; and
* all executive officers and directors as a group.

The table shows the number of shares owned as of March 27, 2014 and the percentage of outstanding common stock owned as of March 27, 2014. Each person has sole voting and investment power with respect to the shares shown, except as noted.

Name and Address Of Beneficial Owner[2]	Amount and Nature of Beneficial Owner	Percent of Class[1]
Estate of Ray D. Reaves	3,037,000	37.7%
Roger D. Bryant	28,000	*
Dan Robinson	96,000	1.2%
Karl Reimers	58,100	*
Debbie Funderburg	16,000	*
Nancy Stephenson	2,500	*
All Officers and Directors as a Group (5 persons)	200,600	2.5%

* indicates less than 1%

(1) The percentages shown are calculated based upon 8,066,336 shares of common stock issued and outstanding at March 27, 2014. In calculating the percentage of ownership, unless as otherwise indicated, all shares of common stock that the identified person or group had the right to acquire within 60 days of the date of this Annual Report upon the exercise of options and warrants or conversion of notes are deemed to be outstanding for the purpose of computing the percentage of shares of common stock owned by such person or group, but are not deemed to be outstanding for the purpose of computing the percentage of the shares of common stock owned by any other person.

(2) Unless otherwise stated, the beneficial owner's address is 609 Castle Ridge Road, Suite 335, Austin, Texas 78746.

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

The Company leased office space from the estate of its majority shareholder in 2013. The lease required monthly payments of $2,500 on a month to month basis. The lease was cancelled in 2014.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

In the last two fiscal years, we have retained Hein & Associates LLP ("Hein") as our independent registered public accounting firm. Hein audited our consolidated financial statements for fiscal 2013 and 2012. We understand the need for our principal accountants to maintain objectivity and independence in their audit of our financial statements. To minimize relationships that could appear to impair the objectivity of our principal accountants, our Audit Committee has restricted the non-audit services that our principal accountants may provide to us primarily to tax services and audit related services. The Board has adopted policies and procedures for pre-approving work performed by our principal accountants.

After careful consideration, the Audit Committee of the Board of Directors has determined that payment of the below audit fees is in conformance with the independent status of the Company's principal independent accountants. Before engaging the auditors in additional services, the Audit Committee considers how these services will impact the entire engagement and independence factors.

The following is an aggregate of fees billed for each of the last two fiscal years for professional services rendered by our principal accountants:

	2013	2012
Audit fees - audit of annual financial statements and review of financial statements included in our quarterly reports, services normally provided by the accountant in connection with statutory and regulatory filings.	$ 117,300	$ 101,900
Audit-related fees - related to the performance of audit or review of financial statements not reported under "audit fees" above	-	-
Tax fees - tax compliance, tax advice and tax planning	23,900	18,800
All other fees - services provided by our principal accountants other than those identified above	-	-
Total fees paid or accrued to our principal accountants	$ 141,200	$ 120,700

ITEM 15 **<u>EXHIBITS AND FINANCIAL STATEMENT SCHEDULES</u>**

(a) Exhibits

3.1 Articles of Incorporation (incorporated by reference to Amendment No. 1 to Form S-2 dated August 1, 1980.)

3.2(b) Articles of Amendment of Articles of Incorporation, dated December 31, 1997 (incorporated by reference to the Company's 10KSB for the year ended December 31, 1997.)

3.3 Bylaws (incorporated by reference to Amendment No. 1 to Form S-2 dated August 1, 1980.)

4.1 Plan of Exchange (incorporated by reference to the Company's definitive proxy statement dated December 8, 1997).

4.2 Indenture (Term Loan) dated June 21, 1999 by and among the Company and Union Planters Bank

4.3 Indenture (Term Loan) dated August 18, 1999 by and among the Company and Union Planters Bank

4.4. Stock Option Agreement (incorporated by reference to the Company's Form S-8 dated May 27, 2005 as filed with the Commission on May 27, 2005.)

4.5 Warrant Agreement and Form of Warrant Certificate (incorporated by reference to the Company's Form S-3 as filed with the Commission on November 22, 2011.)

10.1 Consulting Agreement dated May 9, 2000 between FieldPoint Petroleum Corp. and Parrish Brian & Co. (incorporated by reference to the Company's 10QSB/A for the quarter ended September 30, 2000)

10.2 Executive Employment Agreement, dated March 28, 2001, by and among FieldPoint Petroleum Corp. and Ray D. Reaves (incorporated by reference to the Company's 10KSB for the year ended December 31, 2000.)

10.3 Credit Agreement (Revolving Credit Note) dated December 14, 2000 by and among FieldPoint Petroleum Corp. and Union Planters Bank (incorporated by reference to the Company's 10KSB for the year ended December 31, 2000.)

10.4 Audit Committee Charter adopted by the Company on March 28, 2001(incorporated by reference to the Company's 10KSB for the year ended December 31, 2000.)

10.5 Consulting Agreement dated November 13, 2001 between FieldPoint Petroleum Corp. and TRG Group LLC. (incorporated by reference to the Company's 10QSB for the quarter ended September 30, 2001)

10.6 Loan and Security Agreement with CitiBank, N.A., dated October 18, 2006 (incorporated by reference from the Company's current report on Form 8k dated October 18, 2006 as filed with the Commission on October 20, 2006.)

10.7 Lease Assignment from PXP Gulf Coast, Inc., dated March 11, 2004, incorporated by reference from the Company's Current Report on Form 8-K dated March 11, 2004, as filed with the Commission on March 26, 2004.

10.8 Securities Purchase Agreement (incorporated by reference to the Company's Form SB-2 dated September 20, 2005 as filed with the Commission on September 20, 2005.)

10.9 Registration Rights Agreement (incorporated by reference to the Company's Form S-8 dated May 27, 2005 as filed with the Commission on May 27, 2005.)

10.10 Stock Purchase Agreement (incorporated by reference to the Company's Form 8-K dated February 6, 2006 as filed with the Commission on February 9, 2006.)

10.11 Board Compensation Agreement (incorporated by reference to the Company's Form 8-K dated February 6, 2006 as filed with the Commission on February 9, 2006.)

10.12 Security Agreement (incorporated by reference to the Company's Form 8-K dated October 18, 2006 as filed with the Commission on October 20, 2006).

10.13 Bonus Program (incorporated by reference to the Company's Form 8-K dated October 24, 2008 as filed with the Commission on October 29, 2008.)

10.14 Guaranty Agreement (incorporated by reference to the Company's Form 10-Q dated September 30, 2009 as filed with the Commission on November 16, 2009.)

10.15 First Amendment to Loan & Security Agreement (incorporated by reference to the Company's Form 10-Q dated September 30, 2009 as filed with the Commission on November 16, 2009.)

10.16 Second Amendment to Loan & Security Agreement (incorporated by reference to the Company's Form 10-Q dated September 30, 2009 as filed with the Commission on November 16, 2009.)

10.17 Third Amendment to Loan & Security Agreement (incorporated by reference to the Company's Form 10-Q dated September 30, 2009 as filed with the Commission on November 16, 2009.)

10.18 Fourth Amendment to Loan & Security Agreement (incorporated by reference to the Company's Form 10-Q dated September 30, 2009 as filed with the Commission on November 16, 2009.)

10.19 Fifth Amendment to Loan & Security Agreement (incorporated by reference to the Company's Form 8-K dated March 21, 2014, as filed with the Commission on March 21, 2014.)

14. Code of Ethics (incorporated by reference to the Company's Annual Report on Form 10-KSB for the year ended December 31, 2003 as filed with the Commission on April 14,

2004.)

23	Consent of Hein & Associates LLP
31.1	Certification of Principal Executive Officer required by Section 13a-14(a) of the Exchange Act.
31.2	Certification of Principal Operating Officer and Principal Financial Officer required by Section 13a-14(a) of the Exchange Act.
32.1	Certification of Principal Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of Principal Operating Officer and Principal Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1	Reserve & Economic Evaluation Report
99.2	Estimates of Future Reserve & Revenues Report
99.3	Estimates of Proved Reserves and Revenues
99.4	Letter Report and Certificate of Qualification of Fletcher Lewis Engineering, Inc.
99.5	Letter Report and Certificate of Qualification of PGH Petroleum & Environmental Engineers, L.L.C.
99.6	Letter Report and Certificate of Qualification of Joe C. Neal & Associates

SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

FIELDPOINT PETROLEUM CORPORATION
(Registrant)

Date: March 27, 2014 By: /s/ Roger D. Bryant
Roger D. Bryant, Principal Executive Officer

Date: March 27, 2014 By: /s/ Phillip H. Roberson
Phillip H. Roberson, Principal Financial Officer

In accordance with the Exchange Act, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

By: /s/ Roger D. Bryant Roger D. Bryant Principal Executive Officer, Director	Date: March 27, 2014
By: /s/ Phillip H. Roberson Phillip H. Roberson President, Principal Operating Officer, and Principal Financial Officer	Date: March 27, 2014
By: /s/ Dan Robinson Dan Robinson Director	Date: March 27, 2014
By: /s/ Karl W. Reimers Karl W. Reimers Director	Date: March 27, 2014
By: /s/Debra Funderburg Debra Funderburg Director	Date: March 27, 2014
By: /s/Nancy Stephenson Nancy Stephenson Director	Date: March 27, 2014