VICTORY ENERGY CORP
Form 10-K
November 12, 2013

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 10-K

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

For the fiscal year ended December 31, 2012

OR

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

For the transition period from ____________ to _____________

Commission file number: 002-76219NY

VICTORY ENERGY CORPORATION
(Exact name of registrant as specified in its charter)

Nevada (State or other jurisdiction of incorporation or organization)	87-0564472 (I.R.S. Employer Identification No.)
3355 Bee Caves Road, Suite 608, Austin, Texas (Address of principal executive offices)	78746 (Zip Code)

Registrant's telephone number, including area code: 512-347-7300

Securities registered pursuant to Section 12(b) of the Act: None

Securities registered pursuant to Section 12(g) of the Act: Common Stock, $0.001 par value (Title of class)

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

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

Indicate by check mark whether the registrant (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 registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ¨ No x

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

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

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

Large Accelerated Filer	o	Accelerated Filer	o
Non-Accelerated Filer (do not check if Smaller Reporting Company)	o	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 common equity held by non-affiliates of the registrant, computed by reference to the closing price of such stock on June 29, 2012 was approximately $23,012,225 based on the closing price of such stock and such date of $1.05.

The number of shares outstanding of the Registrant's common stock, $0.001 par value, as of November 12, 2013 was 27,563,619.

VICTORY ENERGY CORPORATION

ANNUAL REPORT ON

FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2012

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EXPLANATORY NOTE

Unless otherwise indicated or the context otherwise requires, all references in this Annual Report on Form 10-K ("Report") to "we," "us," "our," "Victory Energy Corporation" and the "Company" are to Victory Energy Corporation, a Neva corporation, and, unless the context otherwise requires, includes Aurora Energy Partners, a Texas general partnership ("Aurora"). Aurora is a consolidated subsidiary of Victory Energy Corporation for financial statement purposes. Victory Energy Corporation is a 50% partner and the managing partner of Aurora. Unless otherwise indicated, references herein to "$" or "dollars" are to United States dollars and have been presented in accordance with U.S generally accepted accounting principles.

The Company has assessed the amount of non-controlling interest that should be separately stated on the face of the Company's consolidated financial statements and is restating its consolidated financial statements for the impacted periods in this Comprehensive Annual Report on Form 10-K for the fiscal year ended December 31, 2012. The non-controlling interest in Aurora is separately identified in the consolidated stockholders equity section of the consolidated financial statements. As a result of this restatement, the Company estimates that its net loss per share will improve by the effect of the non-controlling interest in the loss of Aurora.

The Company has labeled the 2011 financial information in the Form 10-K "As Restated" and provided explanatoryfootnote disclosures. The Company has also provided quarterly financial information for 2011 and 2012, reconciling the restated quarterly consolidated balance sheets and statements of operations to those included in the Affected Reports. The Audit Committee of the Company's Board of Directors discussed the matters described in this Report with the Company's independent accountants.

Cautionary Notice Regarding Forward Looking Statements

We desire to take advantage of the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. This report contains a number of forward-looking statements that reflect management's current views and expectations with respect to business, strategies, future results and events and financial performance. All statements made in this Annual Report other than statements of historical fact, including statements that address operating performance, events or developments that management expects or anticipates will or may occur in the future, including statements related to revenues, cash flow, profitability, adequacy of funds from operations, statements expressing general optimism about future operating results and non-historical information, are forward looking statements. In particular, the words "believe," "expect," "intend," "anticipate," "estimate," "may," "will," variations of such words, and similar expressi identify forward-looking statements, but are not the exclusive means of identifying such statements and their absence does not mean that the statement is not forward-looking.

Readers should not place undue reliance on these forward-looking statements, which are based on management's current expectations and projections about future events, are not guarantees of future performance, are subject to risks, uncertainties and assumptions and apply only as of the date of this report. Our actual results, performance or achievements could differ materially from the results expressed in, or implied by, these forward-looking statements. In particular, our business, including our financial condition and results of operations and our ability to continue as a going concern may be impacted by a number of factors, including, but not limited to, the following:

· continued operating losses;
· our auditors questioning of our ability to continue as a going concern;
· difficulties in raising additional capital;
· challenges in growing our business;
· designation of our common stock as a "penny stock" under SEC regulations;
· FINRA requirements that may limit the ability to buy and sell our common stock;
· volatility in the price of our common stock;
· the highly speculative nature of an investment in our common stock;
· climate change and greenhouse gas regulations;
· global economic conditions;
· the substantial amount of capital required by our operations;
· the volatility of oil and natural gas prices;
· the high level of risk associated with drilling for and producing oil and natural gas;
· assumptions associated with reserve estimates;
· the potential that drilling activities will not yield oil or natural gas in commercial quantities;
· seismic studies may not guarantee the presence of oil or natural gas in commercial quantities;
· potential exploration, production and acquisitions may not maintain revenue levels in the future;
· future acquisitions may yield revenues or production that differ significantly from our projections;
· difficulties associated with managing a small and growing enterprise;
· strong competition from other oil and natural gas companies;
· the unavailability or high cost of drilling rigs and related equipment;
· our inability to control properties that we do not operate;
· our dependence on key management personnel and technical experts;
· the potential for write-downs in the carrying values of our oil and natural gas properties;
· our compliance with complex laws governing our business;
· our failure to comply with environmental laws and regulations;
· the financial condition of the operators of the properties in which we own an interest;
· terrorist attacks on our operations;
· the dilutive effect of additional issuances of our common stock, options or warrants;
· any impairments of our oil and natural gas properties; and
· the results of pending litigation; and
· state regulatory policies regarding spacing of wells and units.

PART I

Item 1. Business

The Company

Victory Energy Corporation was organized under the laws of the State of Nevada on January 7, 1982. The Company is authorized to issue 47,500,000 shares of $0.001 par value common stock. On January 12, 2012 the Company implemented a 50:1 reverse stock split. All information in this Annual Report on Form 10-K reflects the stock split.

Prior to May 3, 2006 the Company operated as Victory Capital Holdings Corporation among other corporate names.

Copies of the initial Articles of Incorporation of the Company and the Certificates of Amendment to the Articles of Incorporation are incorporated herein by reference.

Our Relationship with Aurora Energy Partners

Victory Energy Corporation is the managing partner of Aurora Energy Partners, a Texas General Partnership ("Aurora"), and holds a 50% partnership interest in Aurora. Aurora is a consolidated subsidiary with Victory Energy Corporation for financial statement purposes. The partnership gives Victory Energy Corporation control of the partnership. Article XI of the partnership agreement cannot be modified unless there is a 100% vote of the partners, therefore Victory Energy Corporation cannot be removed as a managing member of the partnership regardless of the partnership interest held by the partners, and thus consolidation is appropriate for all reporting periods. Currently, Victory Energy Corporation conducts all of its oil and natural gas operations through, and holds all of its oil and natural gas assets through, Aurora, which owns record title to all of the oil and natural gas properties, wells and reserves referred to in this Annual Report on Form 10-K. Through its partnership interest in Aurora, Victory Energy Corporation is the beneficial owner of 50% of such oil and gas properties, wells and reserves held of record by Aurora.

Operational Overview and Strategy

Victory Energy Corporation is an independent, growth oriented oil and natural gas company engaged in the acquisition, exploration and production of oil and natural gas properties. The Company is a partner in Aurora Energy Partners, which is a Texas Partnership that was established in January 2008 by its partners. The other partner in Aurora is the Navitus Energy Group (Navitus), a Texas General Partnership. In an effort to accelerate growth and new capital investment, Aurora's structure was modified on October 1, 2011 to offer new accredited investors of Navitus, a 10% return for five years, to be paid by Victory, one warrant to purchase one share of Victory common stock for every dollar invested and additional benefits. Under this agreement Navitus has the right to contribute up to $15 million dollars into Aurora, and Victory is obligated to match this plus previous contributions made by Navitus and prior Navitus investments; creating a near $53 million portfolio. By utilizing accumulated proved reserves created from the investment of this capital, Victory Energy Corporation has the ability to meet its capital matching obligations, specifically through a combination of traditional financing sources such as private equity placement, credit facilities, and debt. Under the agreement separation of the partners is not mandatory and Victory may raise funds from other sources. All oil and natural gas assets are owned by Aurora during the 5 year term of the partnership. Victory is the managing partner and shares in Aurora's profits and losses via its 50% partnership interest.

The Company is geographically focused onshore, with a primary focus in the Permian Basin of Texas and southeast New Mexico. The Company leverages both internal capabilities and strategic industry relationships to acquire working interest positions in low-to-moderate risk oil and natural gas prospects.

The Company’s strategy is to continue diversifying its interests by targeting additional prospects that are modeled on our most recent success, the Lightnin’ property. On March 27, 2013, the first well at Lightnin’, Cotter #1 went in production. Current flow rates support a rate of cash-flow that is greater than the company produced in all of calendar year 2012. This single property offers the Company at least seven additional well locations, each offering an estimated 128,000 gross barrels of oil equivalent (BOE), for an estimated total gross yield of 1,024,000 BOE (192,000 net). The Company plans to drill two additional wells on this property in 2013. With the combination of higher working interest, the multi-pay stacked formation opportunities provided, low well costs and the production type curve available, the Lightnin’ property is considered a model for all future acquisitions targeted in the Permian basin of Texas and New Mexico. In 2011, approximately 82,000 active wells were drilled in the Permian Basin, making up 71% of all oil production in Texas and 14% of total U.S. production. Analysts estimated there could be another 40 years of drilling opportunity available in this region.

As it executes its strategy, the Company will be targeting investments in larger working interest projects that are weighted toward oil and liquids rich natural gas. This approach of increasing its economic interest should allow it to realize economies of scale, cost efficiencies and, thus improve returns. To further this objective, the Company is managing its cash general and administrative expenses while pursuing additional properties that add revenue at competitive finding and development (F&D) costs per BOE. Lower expenses and additional capital will give the Company flexibility to invest in developing its current asset base. Its increased use of in-house and third party technical and geological capabilities will also help generate additional oil and natural gas prospects with improved working interest positions.

Our primary objectives are two-fold: 1) increase oil and natural gas reserves through the drill bit to expand existing reserve opportunities, 2) grow the business via acquisition of larger oil focused projects with a higher working interest position where possible. To support these objectives, the Company has put in place a highly experienced management and technical team with over 170 years of combined relevant oil and natural gas experience and is continuing to build outside relationships with established operators and geologists.

As of May 20, 2013, the Company had 24 wells on production and 2 wells that have been successfully drilled and are in various stages of completion. The Company's portfolio of producing assets now includes; the Lightnin' property, the Bootleg Canyon Ellenberger Field, the Adams-Baggett Gas Field, the Morgan property, the Uno-Mas property and the Clear Water Wolfberry resource play. Proved commercial accumulations of hydrocarbons now occur in multiple horizons, at depths ranging from 4,700 to 13,100 feet with the majority of proved reserves being located on properties in the prolific Permian Basin of Texas and New Mexico. As the Company continues to drill available locations on its current properties and add properties that are accessible to the Company through its established deal flow pipeline, it anticipates an accelerated pace toward oil-weighted production and the addition of new reserves.

The Company's capital and exploration expenditures, including projects at year end, totaled $1,019,901 for 2012. At December 31, 2012, the Company had $158,165 of cash on hand with no outstanding long term debt during 2012. Navitus Energy Group contributed $1.1 million in cash to Aurora. The Company anticipates that Navitus will make additional contributions to Aurora as the portfolios of properties are developed.

During February 2012, the Company raised $1,815,000 of new capital by issuing convertible debt via a private placement offering (PPM) to investors. This new capital followed the successful completion of a 50:1 reverse stock split.

On March 28, 2013, the Company filed a form 12b-25 with the Securities and Exchange Commission ("SEC) disclosing that is was unable to timely file with the SEC its Annual Report on Form 10-K for the year ended December 31, 2012. The Company required additional time to complete the filing due to requirements to restate the consolidated financial statements associated with the proper presentation of the non-controlling interest ("NCI") in Aurora Energy Partners, which is discussed in further detail in the Note 1 to our audited consolidated financial statements included in this Annual Report on Form 10-K.

Distribution Methods

Each of our fields that produce oil distributes the oil through one purchaser for each field. There is significant demand for oil and there are several companies in our operating areas that purchase oil from small oil producers.

Each of our fields that produce natural gas distributes all of the natural gas that it produces through one purchaser for each field. We have distribution agreements with these natural gas purchasers that provide us a tap into a distribution line of a natural gas distribution company. We are to be paid for our natural gas at either a market price at the beginning of the month or market price at the time of delivery, less any transportation cost charged by the natural gas distribution company.

Competition

We encounter competition from other oil and natural gas companies in all areas of our operations. Because of record high prices for oil, there are many companies competing for the leasehold rights to good oil and natural gas prospects. Additionally, because so many companies are again exploring for oil and natural gas, there is often a shortage of equipment available to do drilling and work over projects. Many of our competitors are large, well-established companies that have been engaged in the oil and natural gas business for much longer than we have and possess substantially larger operating staffs and greater capital resources than we do.

Source and Availability of Raw Materials

We have no significant raw materials. However, we make use of numerous oil field service companies in the drilling and work over of wells. We currently operate in areas where there are numerous oil field service and drilling companies that are available to us.

Marketing Arrangements

There is a ready market for the sale of oil and gas. Each of our fields currently sells all of its oil and gas production on the spot market basis.

Federal Regulations

Our facilities in the United States are subject to federal, state and local environmental laws and regulations. Compliance with these provisions has not had any material adverse effect upon our capital expenditures, net earnings or competitive position. However, the legislative and regulatory burden placed on the industry raises our cost of doing business and therefore could impact profitability. Please refer to Item 1A, Risk Factors.

Regulation of Sale and Transportation of Natural Gas

Historically, the transportation and sales for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 (the NGPA) and Federal Energy Regulatory Commission ("FERC") regulations. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act for all "first sales" of natural gas.

Thus, all of our sales of natural gas may be made at market prices, subject to applicable contract provisions. Sales of natural gas are affected by availability, terms and cost of pipeline transportation. Since 1985, FERC has implemented regulations intended to make natural gas transportation more accessible to gas buyers and sellers on an open access, non-discriminatory basis. We cannot predict what further action FERC will take on these matters. Some of FERC's more recent proposals may, however, adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any action taken materially differently than other natural gas producers, gatherers and marketers with which we compete.

The Outer Continental Shelf Lands Act (the "OCSLA") requires that all pipelines operating on or across the Outer Continental Shelf provides open-access, non-discriminatory service. There are currently no regulations implemented by FERC under its OCSLA authority on gatherers and other entities outside the reach of its NGA jurisdiction. Therefore, we do not believe that any action taken under OCSLA will affect us in a way that materially differs from the way it affects other natural gas producers, gatherers and marketers with which we compete.

Our natural gas sales are generally made at the prevailing market price at the time of sale. Therefore, even though we sell significant volumes to major purchasers, we believe that other purchasers would be willing to buy our natural gas at comparable market prices.

Natural gas continues to supply a significant portion of North America's energy needs and we believe the importance of natural gas in meeting this energy need will continue. The impact of the ongoing economic downturn on natural gas supply and demand fundamentals has resulted in extremely volatile natural gas prices, which is expected to continue.

On August 8, 2005, the Energy Policy Act of 2005 (the “2005 EPA”) was signed into law. This comprehensive act contains many provisions that will encourage oil and natural gas exploration and development in the United States. The 2005 EPA directs FERC and other federal agencies to issue regulations that will further the goals set out in the 2005 EPA. The 2005 EPA amends the NGA to make it unlawful for “any entity,” including otherwise non-jurisdictional producers such as us, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by FERC, in contravention of rules prescribed by FERC. On January 20, 2006, FERC issued rules implementing this provision. The rules make it unlawful in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. The new anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of otherwise non-jurisdictional entities to the extent the activities are conducted “in connection with” gas sales, purchases or transportation subject to FERC jurisdiction. It therefore reflects a significant expansion of FERC’s enforcement authority. We do not anticipate that we will be affected any differently than other producers of natural gas.

In 2007, FERC issued a final rule on annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing (“Order 704”). Under Order 704, wholesale buyers and sellers of more than 2.2 million MBtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors and natural gas marketers are now required to report, on May 1 of each year, beginning in 2009, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. The monitoring and reporting required by these rules have increased our general and administrative expenses. We do not anticipate that we will be affected any differently than other producers of natural gas.

Regulation of the Sale and Transportation of Oil

Our sales of crude oil, condensate and NGL are not currently regulated, and are subject only to applicable contract provisions negotiated by us and our counterparties. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to FERC’s jurisdiction under the Interstate Commerce Act (the “ICA”). In other instances, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes.

The regulation of pipelines that transport oil, condensate and NGL is generally less restrictive than FERC’s regulation of natural gas pipelines under the NGA. Regulated pipelines that transport crude oil, condensate and NGL are subject to common carrier obligations that generally ensure non-discriminatory access. With respect to interstate pipeline transportation subject to regulation of FERC under the ICA, rates generally must be cost-based, although market-based rates or negotiated settlement rates are permitted in certain circumstances. Pursuant to FERC Order No. 561, pipeline rates are subject to an indexing methodology. Under this indexing methodology, pipeline rates are subject to changes in the Producer Price Index for Finished Goods, minus 1%. A pipeline can seek to increase its rates above index levels provided that the pipeline can establish that there is a substantial divergence between the actual costs experienced by the pipeline and the rate resulting from application of the index. A pipeline can seek to charge market based rates if it establishes that it lacks significant market power. In addition, a pipeline can establish rates pursuant to settlement if agreed upon by all current shippers. A pipeline can seek to establish initial rates for new services through a cost-of-service proceeding, a market-based rate proceeding, or through an agreement between the pipeline and at least one shipper not affiliated with the pipeline.

Federal, State or American Indian Leases. In the event we conduct operations on federal, state or American Indian onshore oil and natural gas leases, such operations must comply with numerous regulatory restrictions, including various nondiscrimination statutes, certain on-site security regulations and must also obtain permits issued by the Bureau of Land Management (the “BLM”) or other appropriate federal, tribal or state agencies.

The Mineral Leasing Act of 1920 (the “Mineral Act”) prohibits direct or indirect ownership of any interest in federal onshore oil and natural gas leases by a foreign citizen of a country that denies “similar or like privileges” to citizens of the United States. Such restrictions on citizens of a “non-reciprocal” country include ownership or holding or controlling stock in a corporation that holds a federal onshore oil and natural gas lease. If this restriction is violated, the corporation’s lease can be cancelled in a proceeding instituted by the United States Attorney General. Although the regulations of the BLM (which administers the Mineral Act) provide for agency designations of non-reciprocal countries, there are presently no such designations in effect. We own interests in numerous federal onshore oil and natural gas leases. It is possible that holders of our equity interests may be citizens of foreign countries, which at some time in the future might be determined to be non-reciprocal under the Mineral Act. If any of our equity holders is deemed to be a citizen of a non-reciprocal country, then our interests in federal onshore oil and natural gas leases may be cancelled. Any such cancellation could have a material adverse effect on our financial condition, cash flows and results of operations.

State Regulations

Most states regulate the production and sale of oil and natural gas, including:

- requirements for obtaining drilling permits;
- the method of developing new fields;
- the spacing and operation of wells;
- the prevention of waste of oil and gas resources; and
- the plugging and abandonment of wells.

The rate of production may be regulated and the maximum daily production allowable from both oil and natural gas wells may be established on a market demand or conservation basis or both.

We may enter into agreements relating to the construction or operation of a pipeline system for the transportation of natural gas. To the extent that such natural gas is produced, transported and consumed wholly within one state, such operations may, in certain instances, be subject to the jurisdiction of such state's administrative authority charged with the responsibility of regulating intrastate pipelines. In such event, the rates that we could charge for natural gas, the transportation of natural gas, and the construction and operation of such pipeline would be subject to the rules and regulations governing such matters, if any, of such administrative authority.

Environmental, Health and Safety Regulation

General. Our activities are subject to existing federal, state and local laws and regulations governing environmental quality and pollution control. Although no assurances can be made, we believe that, absent the occurrence of an extraordinary event, compliance with existing federal, state and local laws, regulations and rules regulating the release of materials in the environment or otherwise relating to the protection of human health, safety and the environment will not have a material effect upon our capital expenditures, earnings or competitive position with respect to our existing assets and operations. We cannot predict what effect additional regulation or legislation, enforcement policies, and claims for damages to property, employees, other persons and the environment resulting from our operations could have on our activities.

Our activities with respect to exploration and production of oil and natural gas, including the drilling of wells, are subject to stringent environmental regulation by state and federal authorities, including the USEPA. Such regulations can increase the cost of our activities. Although we believe that compliance with environmental regulations will not have a material adverse effect on us, risks of substantial costs and liabilities are inherent in oil and natural gas production operations, and there can be no assurance that significant costs and liabilities will not be incurred. Moreover it is possible that other developments, such as spills or other unanticipated releases, stricter environmental laws and regulations, and claims for damages to property or persons resulting from oil and natural gas production, would result in substantial costs and liabilities to us.

Solid and Hazardous Waste. We own or lease numerous properties that have been used for production of oil and natural gas for many years. Although we have utilized operating and disposal practices standard in the industry at the time, hydrocarbons or other solid wastes may have been disposed of or released on, under, or from these properties. In addition, many of these properties have been operated by third parties that controlled the treatment of hydrocarbons and solid wastes and the manner in which such substances may have been disposed or released. State and federal laws applicable to oil and natural gas wastes and properties have gradually become stricter over time. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators) or to perform remedial plugging operations to prevent future contamination.

We generate wastes, including hazardous wastes, which are subject to regulation under the federal Resource Conservation and Recovery Act (the “RCRA”) and state statutes. The USEPA has limited the disposal options for certain hazardous wastes. Furthermore, it is possible that certain wastes generated by our oil and natural gas operations that are currently exempt from regulation as “hazardous wastes” may in the future become regulated as “hazardous wastes” under RCRA or other applicable statutes, and therefore may become subject to more rigorous and costly management and disposal requirements.

Naturally Occurring Radioactive Materials (“NORM”) are radioactive materials which precipitate on production equipment or area soils during oil and natural gas extraction or processing. NORM wastes are regulated under the RCRA framework, although such wastes may qualify for the oil and gas hazardous waste exclusion. Primary responsibility for NORM regulation has been a state function. Standards have been developed for worker protection; treatment, storage and disposal of NORM waste; management of waste piles, containers and tanks; and limitations upon the release of NORM-contaminated land for unrestricted use. We believe that our operations are in material compliance with all applicable NORM standards.

Superfund. The Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, or “(“CERCLA”,”), also known as the “Superfund” law, imposes joint and several liabilities, without regard to fault or the legality of the original conduct, in connection on certain persons with respect to the release or threatened release of a “hazardous substance” into the environment. Persons potentially liable under CERCLA. These persons include the current or former owner or and operator of the site where the release occurred and anyone who and persons that disposed or arranged for the disposal of a hazardous substance to the site where the release occurred. Under CERCLA, such persons may be subject to joint and several liabilities for the costs of cleaning up the hazardous substances that have been released into the environment, damages to natural resources and 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.

We own and lease, and may in the future operate, numerous properties that have been used for oil and natural gas exploitation and production for many years. Hazardous substances may have been released on, at or under the properties owned, leased or operated by us, or on, at or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been or are operated by a site. CERCLA also authorizes the USEPA and, in some cases, third parties or by previous owners or operators whose handling, treatment and disposal of hazardous substances were not under our control. These properties and the substances disposed or released on, at or under them may be subject to CERCLA, RCRA and analogous state laws. In certain circumstances, we could be responsible for the removal of previously disposed substances and wastes, remediate contaminated property or perform remedial plugging or pit closure operations to prevent future contamination. In addition, federal and state trustees can also seek substantial compensation for damages to natural resources resulting from spills or releases.

Water discharges. The Federal Water Pollution Control Act, or the “Clean Water Act”, and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including oil and other substances generated by our operations, into waters of the United States or state waters. Under these laws, the discharge of pollutants into regulated waters is prohibited except in accordance with the terms of a permit issued by EPA or an analogous state agency. 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.

The Safe Drinking Water Act, or “SDWA”, and analogous state laws impose requirements relating to underground injection activities. Under these laws, the EPA and state environmental agencies have adopted regulations relating to permitting, testing, monitoring, record keeping and reporting of injection well activities, as well as prohibitions against the migration of injected fluids into underground sources of drinking water.

Air emissions. The Federal Clean Air Act and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, EPA and certain states have developed and continue to develop stringent regulations governing emissions of toxic air pollutants at specified sources. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the Federal Clean Air Act and analogous state laws and regulations.

The Kyoto Protocol to the United Nations Framework Convention on Climate Change became effective in February 2005. Under the Protocol, participating nations are required to implement programs to reduce emissions of certain gases, generally referred to as greenhouse gases that are suspected of contributing to global warming. The United States is not currently a participant in the Protocol, and Congress has not acted upon recent proposed legislation directed at reducing greenhouse gas emissions. However, there has been support in various regions of the country for legislation that requires reductions in greenhouse gas emissions, and some states have already adopted legislation addressing greenhouse gas emissions from various sources, primarily power plants. The oil and natural gas industry is a direct source of certain greenhouse gas emissions, namely carbon dioxide and methane, and future restrictions on such emissions could impact our future operations.

National Environmental Policy Act. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, or “NEPA”. NEPA requires federal agencies, including the Department of Interior, to evaluate major agency to take actions that have the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. All exploration and production activities on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of oil and natural gas projects on federal lands in response to threats to the public health or the environment and to seek to recover from the responsible persons the costs of such action. Certain state statutes impose similar liability. Neither we nor, to our knowledge, our predecessors have been designated as a potentially responsible party by the USEPA under CERCLA or by any state under a similar state law.

Health safety and disclosure regulation. Under CERCLA, the term “hazardous substance” does not include “petroleum, including crude oil or any fraction thereof,” unless specifically listed or designated and the term does not include natural gas, NGL, liquefied natural gas, or synthetic gas usable for fuel. While this “petroleum exclusion” lessens the significance of CERCLA to our operations, we may generate waste that may fall within CERCLA's definition of a “hazardous substance” in the course of our ordinary operations. We also currently own or lease properties that for many years have been used for the exploration and production of oil and natural gas. Although we and, to our knowledge, our predecessors have used operating and disposal practices that were standard in the industry at the time, “hazardous substances” may have been disposed or released on, under or from the properties owned or leased by us or on, under or from other locations where these wastes have been taken for disposal. At this time, we do not believe that we have any liability associated with any Superfund site, and we have not been notified of any claim, liability or damages under CERCLA.

Oil Pollution Act. The Oil Pollution Act of 1990 (the “OPA”) and regulations thereunder impose a variety of regulations on “responsible parties” related to the prevention of oil spills and liability for damages resulting from such spills in certain United States waters. A “responsible party” includes the owner or operator of a facility or vessel, or the lessee or permittee of the area in which an offshore facility is located. The OPA assigns liability to each responsible party for oil removal costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if a spill was caused by gross negligence or willful misconduct or resulted from violation of federal safety, construction or operating regulations. If a party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by the OPA.

The OPA currently establishes a liability limit for onshore facilities of $350 million and for offshore facilities of all removal costs plus $75 million, and lesser limits for some vessels depending upon their size. The regulations promulgated under OPA impose proof of financial responsibility requirements that can be satisfied through insurance, guarantee, indemnity, surety bond, letter of credit, qualification as a self-insurer, or a combination thereof. The amount of financial responsibility required depends upon a variety of factors including the type of facility or vessel, its size, storage capacity, oil throughput, proximity to sensitive areas, type of oil handled, history of discharges and other factors. We carry insurance coverage to meet these obligations, which we believe is customary for comparable companies in our industry. A failure to comply with OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to civil or criminal enforcement actions.

Clean Water Act. The Clean Water Act (the “CWA”) regulates the discharge of pollutants into waters of the United States and adjoining shorelines, including wetlands, and requires a permit for the discharge of pollutants, including petroleum and dredged or fill materials, into such waters and wetlands. Certain state regulations and the general permits issued under the federal National Pollutant Discharge Elimination System program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry operations into certain coastal and offshore waters. Further, the USEPA has adopted regulations requiring certain facilities that store or otherwise handle oil to prepare and implement Spill Prevention, Control and Countermeasure Plans and Facility Response Plans relating to the possible discharge of oil to surface waters. We are required to prepare and comply with such plans and to obtain and comply with discharge permits. The CWA also prohibits spills of oil and hazardous substances to waters of the United States in excess of levels set by regulations and imposes liability in the event of a spill. State laws further provide civil and criminal penalties and liabilities for spills to both surface and groundwater and require permits that set limits on discharges to such waters. We believe we are in substantial compliance with these requirements and that any noncompliance would not have a material adverse effect on us.

Safe Drinking Water Act. The underground injection of oil and natural gas wastes is regulated by the Underground Injection Control (“UIC”) Program, authorized by the federal Safe Drinking Water Act (“SDWA”). The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. In Oklahoma, Louisiana, Mississippi and Texas, no underground injection may take place except as authorized by permit or rule. We currently own and operate various underground injection wells. Failure to comply with our permits could subject us to civil and/or criminal enforcement. We believe that we are in compliance in all material respects with the requirements of applicable state underground injection control programs and our permits and authorizations.

Moreover, our exploration and production activities may involve the use of hydraulic fracturing techniques to stimulate wells and maximize natural gas production. Citing concerns over the potential for hydraulic fracturing to impact drinking water, human health and the environment, and in response to a congressional directive, the USEPA has commissioned a study to identify potential risks associated with hydraulic fracturing. The USEPA published a progress report on this study in December 2012 and a final draft report will be delivered in 2014. Additionally, the BLM proposed to regulate the use of hydraulic fracturing on federal and tribal lands, but following extensive public comment on the proposals, announced it would issue an improved proposal before finalizing new rules. The revised proposal is expected to address disclosure of fluids used in the fracturing process, integrity of well construction, and the management and disposal of wastewater that flows back from the drilling process. Some states now regulate utilization of hydraulic fracturing and others are in the process of developing, or are considering development of, such rules. Depending on the results of the USEPA study and other developments related to the impact of hydraulic fracturing, our drilling activities could be subjected to new or enhanced federal, state and/or local regulatory requirements governing hydraulic fracturing.

Air Emissions. Our operations are subject to local, state and federal regulations for the control of emissions from sources of air pollution. The USEPA has promulgated new rules to address air emissions from the oil and natural gas industry which, among other things, would require installation of equipment to capture certain gases released from new or refitted hydraulically fractured natural gas wells by January 1, 2015. Other new rules, many effective in 2012, impose stricter standards on emissions associated with gas production, storage and transport. The proposals would revise New Source Performance Standards for volatile organic compounds and sulfur dioxide, impose controls on toxics emitted at oil and natural gas wells and their associated production facilities, and limit fugitive emissions from the production, storage and transport equipment. In addition, states impose requirements to address emissions from certain production and associated facilities. We have complied and will continue to comply with these regulations as applicable to our operations. Due to the uncertainties surrounding proposed regulations, we are unable to predict the financial impact going forward.

Administrative enforcement actions for failure to comply strictly with air regulations or permits may be resolved by payment of monetary fines and/or correction of any identified deficiencies. Alternatively, civil and criminal liability can be imposed for non-compliance. Any such action could require us to forego construction or operation of certain air emission sources. We believe that we are in substantial compliance with air pollution control requirements and that, if a particular permit application were denied, we would have enough permitted or permittable capacity to continue our operations without a material adverse effect on any particular producing field.

Climate Change. According to certain scientific studies, emissions of carbon dioxide, methane, nitrous oxide and other gases commonly known as greenhouse gases (“GHG”) may be contributing to global warming of the earth's atmosphere and to global climate change. In response to the scientific studies, legislative and regulatory initiatives have been underway to limit GHG emissions. The U.S. Supreme Court determined that GHG emissions fall within the federal Clean Air Act (“CAA”) definition of an “air pollutant”, and in response the USEPA promulgated an endangerment finding paving the way for regulation of GHG emissions under the CAA. The USEPA has also promulgated rules requiring large sources to report their GHG emissions. Sources subject to these reporting requirements include on- and offshore petroleum and natural gas production and onshore natural gas processing and distribution facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year in aggregate emissions from all site sources. We are not subject to GHG reporting requirements. In addition, the USEPA promulgated rules that significantly increase the GHG emission threshold that would identify major stationary sources of GHG subject to CAA permitting programs. As currently written and based on current operations, we are not subject to federal GHG permitting requirements. Regulation of GHG emissions is new and highly controversial, and further regulatory, legislative and judicial developments are likely to occur. Such developments may affect how these GHG initiatives will impact us. Further, apart from these developments, recent judicial decisions that have not precluded certain state tort claims alleging property damage to proceed against GHG emissions sources may increase our litigation risk for such claims. Due to the uncertainties surrounding the regulation of and other risks associated with GHG emissions, we cannot predict the financial impact of related developments on us.

OSHA. We are subject to the requirements of the federal Occupational Safety and Health Act, or (“OSHA”) and comparable state statutes. The OSHA hazard communication standard, the Emergency Planning and Community Right to Know standards, the USEPA community right-to-know regulations under Title III of the federal Superfund Amendments and Reauthorization Act and similar state statutes require that we use to organize and/or disclose information about hazardous materials stored, used or produced in our operations. Certain of this information must be provided to employees, state and local governmental authorities and local citizens.

We expect to incur capital and other expenditures related to environmental compliance. Although we believe that our compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations, we cannot assure you that the passage of more stringent laws or regulations in the future will not have a negative impact on our financial position or results of operation.

Employees

The Company has 4 full-time employees as of the date of this Annual Report on Form 10-K. We believe that our relationships with our employees are satisfactory. We utilize the services of independent contractors to perform various daily operational duties.

Available Information

We make available free of charge through our "Investor Center – SEC Filings" section of our webs-site at www.vyey.com our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other filings pursuant to Section 13(a) of the Securities Exchange Act of 1934, as amended ("Exchange Act"), and the amendments to such filings, as soon as reasonably practicable after each are electronically filed with, or furnished to the SEC.

Glossary of Certain Industry Terms

The definitions set forth below shall apply to the indicated terms as used throughout this Annual Report on Form 10-K.

Bbl. One barrel (of oil or natural gas liquids).

BOE. One barrel of oil equivalent. A Boe is determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids, which approximates the relative energy content of oil, condensate and natural gas liquids as compared to natural gas. Despite holding this ratio constant at six Mcf to one Bbl, prices have historically often been higher or substantially higher for oil than natural gas on an energy equivalent basis, although there have been periods in which they have been lower or substantially lower.

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

Developed acreage. The number of acres which are allocated or held by producing wells or wells capable of production.

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

Dry hole; dry well. A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

Equivalent volumes. Equivalent volumes are computed with oil and natural gas liquid quantities converted to Mcf on an energy equivalent ratio of one barrel to six Mcf.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in Regulation S-X.

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

HBP. Held by production.

Liquids. Describes oil, condensate, and natural gas liquids.

MBbls. Thousands of barrels of oil or natural gas liquids.

MBoe. Million barrels of oil equivalent.

Mcf. Thousand cubic feet (of natural gas).

Mcfe. Thousand cubic feet equivalent.

MBbls. Millions of barrels of oil or natural gas liquids.

MMcf. Million cubic feet.

MMcfe. Million cubic feet equivalent.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or gross wells expressed in whole numbers.

NGL. Natural gas liquids.

NYMEX. New York Mercantile Exchange.

Present value or PV10% or "SEC PV10%." When used with respect to oil and gas reserves, present value or PV10% or SEC PV10% means the estimated future gross revenue to be generated from the production of net proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, without giving effect to non-property related expenses such as general and administrative expenses, debt service, accretion, and future income tax expense or to depreciation, depletion, and amortization, discounted using monthly end-of-period discounting at a nominal discount rate of 10% per annum.

Productive wells. Producing wells and wells that are capable of production in sufficient quantities to justify completion, including injection wells, salt water disposal wells, service wells, and wells that are shut-in.

Proved developed reserves. Estimated proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

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

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

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

Working Interest or WI. An operating interest which gives the owner the right to drill, produce, and conduct operating activities on the property and a share of production.

Item1A. Risk Factors

Our business is subject to a number of risks including, but not limited to, those described below:

We continue to incur operating losses through 2012.

While the Company has taken steps to reduce general and administrative costs and add further oil and natural gas reserves through additional investment, there is no guarantee the Company will become profitable, or have continued and sustained profitability over the longer term. Our profitability is affected by, among other factors, our ability to have continued access to high-potential reserves, our success in drilling operations, the economic life of any reserves developed, and the market price of crude oil or natural gas. Future losses may adversely our affect our business, financial condition and cash flows.

A decline in the price of our common stock could affect our ability to raise further working capital and adversely impact our operations.

A prolonged decline in the price of our common stock could result in a reduction in the liquidity of our common stock and a reduction in our ability to raise capital. Because our operations are sometimes financed through the sale of equity securities, a decline in the price of our common stock could be especially detrimental to our liquidity and our continued operations. Any reduction in our ability to raise equity capital in the future would force us to reallocate funds from other planned uses and would have a significant negative effect on our business plans and operations, including our ability to develop new projects and continue our current operations. If our stock price declines, we may not be able to raise additional capital or generate funds from operations sufficient to meet our obligations.

If we are not successful in continuing to grow our business, then we may have to scale back or even cease our ongoing business operations.

Our success is significantly dependent on a successful acquisition, drilling, completion and production program. We may be unable to locate recoverable reserves or operate on a profitable basis. If our business plan is not successful, and we are not able to operate profitably, investors may lose some or all of their investment in us.

Trading of our stock may be restricted by the SEC's "Penny Stock" regulations which may limit a stockholder's ability to buy and sell our stock.

The SEC defines and applies “penny stock” regulations to any equity security that has a market price of less $5.00 per share or an exercise price of less than $5.00 per share, subject to certain exceptions. Our securities are covered by the penny stock rules, which impose additional sales practice requirements on broker-dealers who sell to persons other than established customers or "accredited investors." The term "accredited investor" refers generally to institutions with assets in excess of $5,000,000 or individuals with a net worth in excess of $1,000,000 (excluding the value of primary residence and mortgage debt on primary residence) or annual income exceeding $200,000 or $300,000 jointly with his or her spouse. The penny stock rules require a broker-dealer, prior to a transaction in a penny stock not otherwise exempt from the rules, to deliver a standardized risk disclosure document in a form prepared by the SEC that provides information about penny stocks and the nature and level of risks in the penny stock market. The broker-dealer also must provide the customer with current bid and offer quotations for the penny stock, the compensation of the broker-dealer and its salesperson in the transaction and monthly account statements showing the market value of each penny stock held in the customer's account. The bid and offer quotations, and the broker-dealer and salesperson compensation information, must be given to the customer orally or in writing prior to effecting the transaction and must be given to the customer in writing before or with the customer's confirmation. In addition, the penny stock rules require that prior to a transaction in a penny stock not otherwise exempt from these rules; the broker-dealer must make a special written determination that the penny stock is a suitable investment for the purchaser and receive the purchaser's written agreement to the transaction. These disclosure requirements may have the effect of reducing the level of trading activity in the secondary market for the stock that is subject to these penny stock rules. Consequently, these penny stock rules may affect the ability of broker-dealers to trade our securities. We believe that the penny stock rules discourage investor interest in and limit the marketability of, our common stock.

FINRA sales practice requirements may also limit a stockholder’s ability to buy and sell our stock.

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

Trading in our common shares has been volatile and with low trading volumes, making it more difficult for our stockholders to sell their shares or liquidate their investments with predictability.

Our common shares are currently quoted on the OTC Markets. The trading price of our common shares has been subject to wide fluctuations and low trading volumes. Trading prices of our common shares may fluctuate in response to a number of factors, many of which will be beyond our control. The stock market has generally experienced extreme price and volume fluctuations that have often been unrelated or disproportionate to the operating performance of companies with no current business operation. There can be no assurance that trading prices and price earnings ratios previously experienced by our common shares will be matched or maintained. These broad market and industry factors may adversely affect the market price of our common shares, regardless of our operating performance. In the past, following periods of volatility in the market price of a company's securities, securities class-action litigation has often been instituted. Such litigation, if instituted, could result in substantial costs for us and a diversion of management's attention and resources.

Our securities are considered highly speculative.

Our securities are considered highly speculative, generally because of the nature of our business and the early stage we are in of building a long life asset base. While operating revenues are planned to increase over time, through our capital and exploration program, there are risks associated with drilling success, oil and natural gas prices, and our ability to raise additional monies through share offerings or debt. Access to capital is vital and unless the revenue base grows over time that could prove difficult to accomplish.

Potential legislative and regulatory actions addressing climate change could increase our costs, reduce our revenue and cash flow from oil and gas sales or otherwise alter the way we conduct our business.

Future changes in the laws and regulations to which we are subject may make it more difficult or expensive to conduct our operations and may have other adverse effects on us. For example, the USEPA has issued a notice of finding and determination that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, which allows the USEPA to begin regulating emissions of GHGs under existing provisions of the CAA. The USEPA has begun to implement GHG-related reporting and permitting rules. Similarly, the U.S. Congress has considered and may in the future consider “cap and trade” legislation that would establish an economy-wide cap on emissions of GHGs in the United States and would require most sources of GHG emissions to obtain GHG emission “allowances” corresponding to their annual emissions of GHGs. Any laws or regulations that may be adopted to restrict or reduce emissions of GHGs would likely require us to incur increased operating costs and could have an adverse effect on demand for our production.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Congress has considered legislation to amend the SDWA to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process and other legislation regulating hydraulic fracturing has been considered, and in some cases adopted, at various levels of government. Hydraulic fracturing is an important and commonly used process in the completion of unconventional gas wells in shale formations as well as tight conventional formations. This process involves the injection of water, sand and chemicals under pressure into rock formations to stimulate gas production. Sponsors of these bills have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies and/or that hydraulic fracturing could pose a variety of other risks. Any additional level of regulation 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.

Gas drilling and production operations require adequate sources of water to facilitate the fracturing process and the disposal of that water when it flows back to the wellbore. If we are unable to obtain adequate water supplies and dispose of the water we use or remove at a reasonable cost and within applicable environmental rules, our ability to produce gas commercially and in commercial quantities would be impaired.

New environmental regulations governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase operating costs and cause delays, interruptions or termination of operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial performance. Water that is used to fracture gas wells must be removed when it flows back to the wellbore. Our ability to remove and dispose of water will affect our production and the cost of water treatment and disposal may affect our profitability. The imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct hydraulic fracturing or disposal of waste, including produced water, drilling fluids and other wastes associated with the exploration, development and production of gas.

Proposed changes to U.S. tax laws, if adopted, could have an adverse effect on our business, financial condition, results of operations and cash flows.

The U.S. President's Fiscal Year 2013 Budget Proposal includes provisions that would, if enacted, make significant changes to U.S. tax laws applicable to oil and gas exploration and production companies. These changes include, but are not limited to:

- the repeal of the limited percentage depletion allowance for oil and natural gas production in the United States;
- the elimination of current deductions for intangible drilling and development costs;
- the elimination of the deduction for certain domestic production activities; and
- an extension of the amortization period for certain geological and geophysical expenditures.

Members of the U.S. Congress have considered similar changes to the existing federal income tax laws that affect oil and natural gas exploration and production companies. It is unclear whether these or similar changes will be enacted. The passage of this legislation or any similar changes in federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to U.S. oil and gas exploration and development. Any such changes could have an adverse effect on our financial position, results of operations and cash flows.

The adoption and implementation of new statutory and regulatory requirements for derivative transactions could have an adverse impact on our ability to hedge risks associated with our business and increase the working capital requirements to conduct these activities.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (“Dodd-Frank Act”) provides for new statutory and regulatory requirements for derivative transactions, including oil and natural gas hedging transactions. Among other things, the Dodd-Frank Act provides for the creation of position limits for certain derivatives transactions, as well as requiring certain transactions to be cleared on exchanges for which cash collateral will be required. In October 2011, the CFTC approved final rules that establish position limits for futures contracts on 28 physical commodities, including four energy commodities, and swaps, futures and options that are economically equivalent to those contracts. The rules provide an exemption for “bona fide hedging” transactions or positions, but this exemption is narrower than the exemption under existing CFTC position limit rules. These newly approved CFTC position limits rules were vacated by the United States District Court for the District of Columbia in September 2012, although the CFTC has stated that it will appeal the District Court’s decision.

It is not possible at this time to predict with certainty the full effect of the Dodd-Frank Act and CFTC rules on us and the timing of such effects. The Dodd-Frank Act may require us to comply with margin requirements and with certain clearing and trade-execution requirements if we do not satisfy certain specific exceptions. The Dodd-Frank Act may also require the counterparties to our derivatives contracts to transfer or assign some of their derivatives contracts to a separate entity, which may not be as creditworthy as the current counterparty. Depending on the rules adopted by the CFTC or similar rules that may be adopted by other regulatory bodies, we might in the future be required to provide cash collateral for our commodities hedging transactions under circumstances in which we do not currently post cash collateral. Posting of such additional cash collateral could impact liquidity and reduce our cash available for capital expenditures. A requirement to post cash collateral could therefore reduce our ability to execute hedges to reduce commodity price uncertainty and thus protect cash flows. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable.

Oil and gas prices are volatile. Declines in commodity prices have adversely affected, and in the future may adversely affect, our financial condition and results of operations, cash flows, access to the capital markets and ability to grow.

Our revenue reserves, cash flows, profitability and future rate of growth substantially depend upon the market prices of oil and natural gas. Our ability to borrow funds or obtain additional capital, as well as the carrying value of our properties, is substantially dependent on prevailing prices of oil and natural gas. Historically, the markets for oil and gas have been volatile, and those markets are likely to continue to be volatile in the future. It is impossible to predict future oil and gasoil and gas price movements with certainty. The prices we receive for our oil and natural gas depend upon factors beyond our control, including, among others:

- changes in the supply of and demand for oil and natural gas;
- market uncertainty;
- level of consumer product demands;
- weather conditions;
- domestic governmental regulations and taxes;
- price and availability of alternative fuels;
- political and economic conditions in oil producing countries;
- actions by the Organization of Petroleum Exporting Countries;
- price of oil and natural gas imports; and
- overall domestic and foreign economic conditions.

These factors make it very difficult to predict future commodity price movements with any certainty. Substantially all of our oil and natural gas sales are made in the spot market or pursuant to contracts based on spot market prices and are not long-term fixed price contracts. Further, oil prices and gas prices do not necessarily fluctuate in direct relation to each other.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our success largely depends on the success of our exploitation, exploration, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control; including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Our costs of drilling, completing and operating wells are often uncertain before drilling commences. Overruns in budgeted expenditures are a common risk that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel drilling operations, including the following:

- delays imposed by or resulting from compliance with regulatory requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions;
- reductions in oil and gas prices; and
- oil and gas property title problems.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of our reported reserves. In order to prepare our estimates, we must project production rates and the timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires that economic assumptions be made about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of oil and natural gas reserves are inherently imprecise.

Actual future production, oil and natural gas prices received, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reported reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

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

There is no way to predict in advance of drilling and testing whether any particular drilling prospect will yield oil or natural gas in sufficient quantities to recover drilling and completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects.

We depend on successful exploration, development and acquisitions to maintain revenue in the future.

In general, the volume of production from oil and gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Except to the extent that we conduct successful exploration and development activities or acquire properties containing proved reserves, or both, our proved reserves will decline as reserves are produced. Our future oil and gas production is, therefore, highly dependent on our level of success in finding or acquiring additional reserves. Additionally, the business of exploring for, developing, or acquiring reserves is capital intensive. Recovery of our reserves, particularly undeveloped reserves, will require significant additional capital expenditures and successful drilling operations. To the extent cash flow from operations is reduced and external sources of capital become limited or unavailable, our ability to make the necessary capital investment to maintain or expand our asset base of oil and gas reserves would be impaired. In addition, we may be required to find partners for any future exploratory activity. To the extent that others in the industry do not have the financial resources or choose not to participate in our exploration activities, we will be adversely affected.

We are not the operator of our oil and gas properties and therefore are not in a position to control the timing of development efforts, the associated costs or the rate of production of the reserves on such properties.

- the timing and amount of capital expenditures;
- the availability of suitable drilling equipment, production and transportation infrastructure and qualified operating personnel;
- the operator’s expertise and financial resources;
- approval of other participants in drilling wells;

- selection of technology; and
- the rate of production of the reserves.

In addition, when we are not the majority owner or operator of a particular oil or gas project, if we are not willing or able to fund our capital expenditures relating to such projects when required by the majority owner or operator, our interests in these projects may be reduced or forfeited.

Our future acquisitions may yield revenues and/or production that vary significantly from our projections.

In acquiring producing properties we assess the recoverable reserves, future oil and gas prices, operating costs, potential liabilities and other factors relating to such properties. Our assessments are necessarily inexact and their accuracy is inherently uncertain. Our review of a subject property in connection with our acquisition assessment will not reveal all existing or potential problems or permit us to become sufficiently familiar with the property to assess fully its deficiencies and capabilities.

We may not inspect every well, and we may not be able to identify structural and environmental problems even when we do inspect a well. If problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of those problems. Any acquisition of property interests may not be economically successful, and unsuccessful acquisitions may have a material adverse effect on our financial condition and future results of operations.

We cannot assure you that:

- we will be able to identify desirable oil and gas prospects and acquire leasehold or other ownership interests in such prospects at a desirable price;
- any completed, currently planned, or future acquisitions of ownership interests in oil and gas prospects will include prospects that contain proved oil and gas reserves;
- we will have the ability to develop prospects which contain proven natural gas or oil reserves;
- we will have the financial ability to consummate additional acquisitions of ownership interests in oil and gas prospects or to develop the prospects which we acquire to the point of production; or
- we will be able to consummate such additional acquisitions on terms favorable to us.

We face strong competition from other oil and gas companies.

We encounter competition from other oil and gas companies in all areas of our operations, including the acquisition of exploratory prospects and proved properties. Our competitors include major integrated oil and gas companies and numerous independent oil and gas companies, individuals, and drilling and income programs. Many of our competitors are large, well-established companies that have been engaged in the oil and gas business much longer than we have and possess substantially larger operating staffs and greater capital resources than we do. These companies may be able to pay more for productive oil and gas properties and may be able to define, evaluate, bid for, and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may be able to expend greater resources on the existing and changing technologies that we believe are and will be increasingly important to attaining success in the industry. We may not be able to conduct our operations, evaluate, and select suitable properties and consummate transactions successfully in this highly competitive environment.

The unavailability or high cost of drilling rigs, equipment, supplies or personnel could affect adversely our ability to execute on a timely basis our exploration and development plans within budget, which could have a material adverse effect on our financial condition and results of operations.

Shortages or the high cost of drilling rigs, equipment, supplies or personnel could delay or affect adversely our exploration and development operations, which could have a material adverse effect on our financial condition and results of operations. Demand for drilling rigs, equipment, supplies, and personnel are currently very high in the areas in which we operate. An increase in drilling activity in the areas in which we operate could further increase the cost and decrease the availability of necessary drilling rigs, equipment, supplies and personnel.

We depend on key management personnel and technical experts. The loss of key employees or access to third party technical expertise could impact our ability to execute our business.

If we lose the services of the senior management, or access to independent land men, geologists and reservoir engineers with whom the Company has strategic relationships, our ability to function and grow could suffer, in turn, negatively affecting our business, financial condition and results of operations.

The marketability of our natural gas production depends on facilities that we typically do not own or control, which could result in a curtailment of production and revenues.

The marketability of our gas production depends in part upon the availability, proximity and capacity of gas gathering systems, pipelines and processing facilities. We generally deliver gas through gas gathering systems and gas pipelines that we may not own under interruptible or short-term transportation agreements. Under the interruptible transportation agreements, the transportation of our gas may be interrupted due to capacity constraints on the applicable system, due to maintenance or repair of the system, or for other reasons as dictated by the particular agreements. Our ability to produce and market natural gas on a commercial basis could be harmed by any significant change in the cost or availability of such markets, systems or pipelines.

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

Accounting rules require that we review periodically the carrying value of our oil and natural gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties. In the future should our properties serve as collateral for credit facilities, a write down in the carrying values of our properties could require us to repay debt earlier than would otherwise be required. A write-down would also constitute a non-cash charge to earnings. It is likely that the effect of such a write-down could also negatively impact the trading price of our securities.

We account for our oil and natural gas properties using the successful efforts method of accounting. Under this method, all development costs and acquisition costs of proved properties are capitalized and amortized on a units-of-production basis over the remaining life of proved developed reserves and proved reserves, respectively. Costs of drilling exploratory wells are initially capitalized, but charged to expenses if and when a well is determined to be unsuccessful. We evaluate impairment of our proved oil and natural gas properties whenever events or changes in circumstances indicate an asset's carrying amount may not be recoverable. The risk that we will be required to write down the carrying value of our oil and natural gas properties increases when oil and natural gas prices are low or volatile. In addition, write-downs would occur if we were to experience sufficient downward adjustments to our estimated proved reserves or the present value of estimated future net revenues.

We are subject to complex laws that can affect the cost, manner or feasibility of doing business.

The exploration, development, production and sale of oil and natural gas are subject to extensive federal, state, local and international regulation. We may be required to make large expenditures to comply with such governmental regulations. Matters subject to regulation include:

- natural disasters;
- permits for drilling operations;
- drilling and plugging bonds;
- reports concerning operations;
- the spacing and density of wells;
- unitization and pooling of properties;
- environmental maintenance and cleanup of drill sites and surface facilities; and
- Protection of human health.

From time to time, regulatory agencies have also imposed price controls and limitations on production by restricting the rate of flow of oil and gas wells below actual production capacity in order to conserve supplies of oil and gas.

Under these laws, we could be liable for personal injuries, property damage and other damages. Failure to comply with these laws also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws could change in ways that substantially increase our costs. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially adversely affect our financial condition and results of operations.

The financial condition of our operators could negatively impact our ability to collect revenues from operations.

We may not operate all of the properties in the future in which we have working interests. In the event that an operator of our properties experiences financial difficulties, this may negatively impact our ability to receive payments for our share of net production that we are entitled to under our contractual arrangements with such operator. While we seek to minimize such risk by structuring our contractual arrangements to provide for production payments to be made directly to us by first purchasers of the hydrocarbons, there can be no assurances that we can do so in all situations covering our non-operated properties.

We may issue additional shares of capital stock that could affect the value of existing holders of the Company's stock, stock options, or warrants.

Our board of directors is authorized to issue additional classes or series of shares of our capital stock without any action on the part of our stockholders. Our board of directors also has the power, without stockholder approval, to set the terms of any such classes or series of shares of our capital stock that may be issued, including voting rights, dividend rights, conversion features, preferences over shares of our existing class of common stock with respect to dividends or if we liquidate, dissolve or wind up our business and other terms. If we issue shares of our capital stock in the future that have preference over shares of our existing class of common stock with respect to the payment of dividends or upon our liquidation, dissolution or winding up, or if we issue shares of capital stock with voting rights that dilute the voting power of shares of our existing class of common stock, the rights of holders of shares of our common stock or the trading price of shares of our common stock and, as a result, the market value of the options and warrants into shares of common stock could be adversely affected.

Our results of operations could be adversely affected as a result of impairments of oil and natural gas properties.

While we provide that our assets will be depleted over the estimated productive reserves of the oil and natural gas wells, these assets must also be tested at least annually for impairment. Management makes certain estimates and assumptions when determining the fair value of net assets and liabilities, including, among other things, an assessment of market conditions, projected cash flows, investment rates, cost of capital and growth rates, which could significantly impact the reported value of drilling costs and other intangible assets. Fair value is determined using a combination of the discounted cash flow, market multiple and market capitalization valuation approaches. Absent any impairment indicators, we perform our impairment tests annually during the fourth quarter. Any future impairment, including impairments of the carrying values of drilling costs and other intangible assets, would negatively impact our results of operations for the period in which the impairment is recognized.

Pending litigation may place a financial burden on our resources and the outcome of the litigation may not be favorable to the Company.

We are currently defending two lawsuits filed against us by landowners for trespass. Litigation continues and the outcome is uncertain. The risk is that our investment in two Adams-Baggett gas wells could be lost.

We are also prosecuting a lawsuit against our former drilling contractor, former operator, and other related parties. In that case, an interlocutory Default Judgment against the defendants was awarded to Victory and James Capital, which is a general partner of Navitus. The judgment amounted to $17,183,987. No monies have yet been received related to this favorable judgment.

Item 1B. Unresolved Staff Comments

We are a "smaller reporting company" as defined by Rule 12b-2 under the Securities Exchange Act, and as such, are not required to provide the information required under this item.

Item 2. Properties

Office Space Leases.

Our executive office space lease is set to expire on June 30, 2014 and is for approximately 1,200 square feet at 3355 Bee Caves Road, Suite 608, Austin, TX 78746. The monthly lease cost is $2,250.

Portfolio.

As of May 24, 2013, the Company, through Aurora had 24 wells in production and 2 wells that have been successfully drilled and were in various stages of completion. The Company's producing portfolio of producing assets now includes; the Lightnin' property, the Bootleg Canyon Ellenberger Field, the Adams-Baggett Gas Field, the Morgan property, the Uno-Mas property and the Clear Water Wolfberry resource play. Proved commercial accumulations of hydrocarbons now occur in multiple horizons, at depths ranging from 4,700 to 13,100 feet with the majority of proved reserves being located on properties in the prolific Permian Basin of Texas and New Mexico. As the Company continues to drill available locations on its current properties and add properties that are accessible to the Company through its established deal flow pipeline, it anticipates an accelerated pace toward oil-weighted production and the addition of new reserves.

On March 27, 2013, the first well at Lightnin', Cotter #1 went in production. Current flow rates support a rate of cash-flow that is greater than the Company produced in all of calendar year 2012. On this single property, the Company has the opportunity to drill at least seven additional well locations, each offering an estimated 128,000 gross barrels of oil equivalent (BOE), for an estimated total gross yield of 1,024,000 BOE (192,000 net). The Company plans to drill two additional wells on this property in 2013.

With the combination of higher working interest, the multi-pay stacked formation opportunities provided, low well costs and the production type curve available, the Lightnin property is considered a model for all future acquisitions targeted in the prolific Permian Basin of Texas and New Mexico.

The Lightnin' Property, Glascock County, Texas

In March 2012, the Company, through its ownership in Aurora acquired a 75% working interest and a 56.25% net revenue interest in 320 gross acres known as the Lightnin' Property. This property is located in the very active Permian Basin resource play known as the Wolfberry. In January 2013, the Company farmed out 50% of its working interest and selected an operator for the prospect. The Company now holds a 25% working interest and an 18.75% net revenue interest in the project. The first well, the Cotter #1, was spud in January 2013, completed in February and brought into production in late March. The Lightnin' property holds at least seven additional well locations, each offering an estimated 128,000 gross barrels of oil equivalent (BOE), for an estimated total gross yield of 1,024,000 BOE (192,000 net). The Company plans to drill two additional wells on this property in 2013. There were no proved reserves associated with this property in the Company's reserve report for the period ended December 31, 2012.

The Bootleg Canyon Property, Pecos County, Texas

The Company, through its ownership in Aurora owns a 5% working interest and a 3.75% net revenue interest in 5,000 gross acres known as the Bootleg Canyon property. The first well on this property was drilled in June of 2011. At the end of 2012 there were two producing oil wells on the property. A third well was successfully completed as a gas well in early 2013. There are two proved producing wells and one proved undeveloped well location in the Company's reserve report for the period ended December 31, 2012. Additional well locations are being evaluated for drilling in 2013.

The Adams-Baggett Property, Crocket County, Texas

The Company, through its ownership in Aurora, holds a working interest in nine wells on the Adams-Baggett Property; 100% working interest and a 75% net revenue interest in seven wells and a 50% working interest with 38% net revenue interest in two wells. The Company received its first production revenue from this field in March of 2008 and continues to receive income today. Due to its higher BTU content per cubic foot, natural gas from the Canyon Sandstone generally receives a 25% or more price premium above the standard market price for natural gas.

The Morgan Property, Martin County, Texas

In November 2012, the Company, through its ownership in Aurora Energy Partners acquired a 3% working interest and a 2.25% net revenue interest in 80 gross acres known as the Morgan Property. This property is located in the Permian Basin Wolfberry Play. The first well, Morgan #1 was spud in December 2012 and reached total depth (10,616 feet) in January 2013. The Morgan #1 was fracture stimulated and completed in March 2013. The well is currently producing both oil and natural gas while the well continues to unload frac fluids. There are two proved undeveloped well locations included in the Company's reserve report for the period ended December 31, 2012.

The Uno-Mas Property, Lea County, New Mexico

In September 2011, the Company, through its ownership in Aurora, acquired a 10% working interest and a 7.5% net revenue interest in 320 gross acres known as the Uno-Mas Property. In December 2011, the Company successfully completed the Uno-Mas #1 re-entry well in the Mississippian formation. The well is currently producing oil and natural gas to sales. In 2012 the Company entered into a farm out agreement with an operator covering the shallower formations on the Uno-Mas Property. In exchange for the farm out rights, the operator has agreed to drill four wells. The Company will be carried through the tanks on the first two wells and then will be given the opportunity to participate on a heads-up basis on the next two wells bearing its working interest share of the well costs. Two of these wells (Hickory 14 State #1 and Milan 12 State #1) have been successfully drilled and are in various stages of completion.

Under the farm out agreement the Company owns a 1.25% carried working interest and a .9375% net revenue interest in the first two wells which reverts to a 2.5% working interest 1.875% net revenue interest once the wells payout. If the shallower formations in the Hickory and Milan prove to be successful, additional potential pay may be available in the Uno-Mas #1 re-entry well-bore.

Clearwater Wolfberry Resource Play, Howard County, Texas

In April 2011, the Company, through its ownership in Aurora acquired a 1.5% working interest and a 1.125% net revenue interest in 3,186 gross acres known as the Clearwater Property. At the time of acquisition this property held two producing wells and a third exploration well was in progress. At year-end 2011, there were three producing oil wells on this property. During February 1, 2012 the Company assigned approximately 944 gross acres of mineral rights related to the Hamlin 26 and Hamlin 24 tracts to another operator in exchange for an overriding royalty interest proportional to the working interest held by the Company. In exchange for the assignment, the Company retained a 0.375% overriding royalty interest in the 944 gross acres. The Company still owns a 1.5% working interest and a 1.125% net revenue interest in the remaining 2,242 acres.

The Chapman Ranch Property, Nueces County, Texas

In April 2012, the Company, through its ownership in Aurora acquired a 5% working interest and a 3.75% net revenue interest in 320 gross acres known as the Chapman Ranch Property. The first well was drilled and completed in July of 2012. Multiple pay zones were present in the well-logs; however oil and natural gas production from the target formation was not of a commercial quantity. The operator has determined that a different geological zone may be productive and the working interest partners have elected to participate in the completion of this zone. Recompletion is anticipated in the second quarter of 2013.

The Pinetop Property, Lea County, New Mexico

In April 2012, the Company, through its ownership in Aurora, acquired a before payout (BPO) working interest of 4% with a 2.94% net revenue interest and an after payout (APO) working interest of 3% with a 2.205% net revenue interest in this 1,201 gross acre property. The first of nine (9) development wells was spud in June 2012 and was successfully completed by the operator. The well had initial flow rates of over 400 barrels of oil per day and unmetered flow of 300 Mcf of natural gas per day. Once on production, the well naturally flowed over 3,000 barrels of oil and 2,125 Mcf of natural gas during the first ten days of operation. After a few weeks, production dramatically decreased to less than 10 BO per day. The well was later put on rod-pump; however production of commercial volumes did not occur. The operator has evaluated the previously producing formation (Lower Cisco) and believes that fracture porosity was not significant enough to produce additional oil beyond the 3,000 barrel pocket that generated the initial production. Two additional formations (Upper Cisco and Wolfcamp) are now being targeted for re-completion. The test of these recompletions is anticipated to occur in June 2013. If the Upper Cisco and Wolfcamp formations prove to be productive, eight additional 3D seismic supported drilling locations remain.

Developed and Undeveloped Lease Acreage

The following table sets forth certain information regarding developed and undeveloped leasehold acreage held by Aurora as of December 31, 2012. “Developed Acreage” refers to acreage on which wells have been drilled or completed to a point that would permit production of oil and natural gas in commercial quantities. “Undeveloped Acreage” refers to acreage on which wells have not been drilled or completed to a point that would permit production of oil and natural gas in commercial quantities whether or not the acreage contains proved reserves.

			Developed Acreage		Undeveloped Acreage		Total Acreage	
	WI %		Gross	Net	Gross	Net	Gross	Net
Adams-Baggett Ranch								
Adams-Baggett Ranch	100	%	140.0	140.0	-	-	140.0	140.0
Adams-Baggett Ranch	50	%	40.0	20.0	-	-	40.0	20.0
The Bootleg Canyon Property								
Bootleg Prospect	5.00	%	320.0	16.0	5,127.4	256.4	5,447.4	272.4
Saddle Butte Prospect	3.00	%	-	-	2,560.0	76.8	2,560.0	76.8
The Lightnin' Property	25.00	%	-	-	320.0	80.0	320.0	80.0
The Uno-Mas Property	10	%	160.0	16.0	160.0	2.0	320.0	18.0
The Morgan Property	3.00	%	-	-	86.0	2.6	86.0	2.6
The Chapman Ranch Property	5.00	%	80.0	4.0	240.0	12.0	320.0	16.0
The Pinetop Property	4.00	%	80.0	3.2	1,120.0	44.8	1,200.0	48.0
Clearwater Wolfberry Resource Play	1.50	%	320.0	4.8	1,922.0	28.8	2,242.0	33.6
*Royalty Interest Acreage	-		-	-	944.0	3.5	944.0	3.5
Total Acreage			1,140.0	204.0	12,479.4	506.9	13,619.4	710.9

Internal Controls Over Reserve Estimates, Technical Qualifications and Technologies Used

The Company’s policies regarding internal controls over reserve estimates requires reserves to be in compliance with the SEC definitions and guidance, and for reserves to be prepared by an independent third party reserve engineering firm and reviewed by certain members of senior management.

Estimates of our reserves were prepared by an independent reserve engineer, Mr. James Nicolson who specializes in preparing reservoir studies, reserve estimates, and property evaluations. Mr. Nicolson, a Registered Professional Engineer, is a member of the Society of Petroleum Engineers, and a former chairman of the Permian Basin Oil & Gas Recovery Conference. Our independent consultants, including a geologist and an oil & gas operations professional have reviewed and approved the reserve report which is filed as an exhibit to this Annual Report on Form 10-K.

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At December 31, 2012, our proved developed reserves were 18% oil and 82% gas and liquids, respectively. The following table sets forth our estimated proved oil and natural gas reserves for the 21 wells and the PW value of such reserves as of December 31, 2012 and 2011.

Total Estimated Proved Reserves	2012			2011		
Oil (MBbl)		24.3			8.0	
Gas (Mcf)		679.4			691.1	
% Oil		18	%		6	%
% Proved Developed		92	%		100	%
PV - 10% (in thousands)	$	1,745.3		$	1,357.4	

Reconciliation of PV-10 to Standardized Measure

PV-10 is derived from the Standardized Measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the Standardized Measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the Standardized Measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the Standardized Measure of discounted future net cash flows. Our PV-10 measure and the Standardized Measure of discounted future net cash flows do not purport to represent the fair value of our oil and natural gas reserves.

The following table provides a reconciliation of PV-10 to the Standardized Measure of discounted future net cash flows at December 31, 2012 and 2011:

	December 31,			
	2012		2011	
	(In Thousands)			
PV-10	$	1,745.3	$	1,357.4
Present value of future income taxes discounted at 10%		601.1		461.5
Standardized Measure of discounted future net cash flows	$	1,144.2	$	895.9

Estimated future net revenues

The following table sets forth the estimated future net revenues, excluding derivative contracts, from proved reserves, the present value of those net revenues (PV-10) and the standardized measure values at December 31, 2012 and 2011:

	December 31,			
	2012		2011	
	(In Thousands)			
Future net revenues	$	3,342.6	$	2,742.1
Present value of net revenues:				
Before income tax (PV-10)		1,745.3		1,357.4
After income tax (Standardized Measure)		1,144.2		898.9

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Productive Wells

Productive wells are producing wells or wells capable of production. This does not include water source wells, water injection wells or water disposal wells. Productive wells do not include any wells in the process of being drilled and completed that are not yet capable of production, but does include old productive wells that are currently shut-in, because they are still capable of production. The following table sets forth the number of productive oil and natural gas wells in which we owned an interest as of December 31, 2012 and 2011.

	December 31,			
	2012		2011	
	Gross	Net	Gross	Net
Natural Gas	10.0	8.1	9.0	8.0
Oil	11.0	0.4	8.0	0.3
Totals	21.0	8.5	17.0	8.3

Technologies Used in Establishing Proved Reserves in 2012 and 2011

Our proved reserves in 2012 and 2011 were based on estimates generated through the integration of available and appropriate data, utilizing well established technologies that have been demonstrated in the field to yield repeatable and consistent results.

Data used in these integrated assessments included information obtained directly from the subsurface via wellbores, such as well logs, reservoir core samples, fluid samples, static and dynamic pressure information, production test data, and surveillance and performance information. The data utilized also included subsurface information obtained through indirect measurements, including high-quality 2-D and 3-D seismic data, calibrated with available well control. Surface geological information was also utilized in the preparation of the data where applicable. The tools used to interpret the data included proprietary seismic processing software, proprietary reservoir modeling and simulation software, and commercially available data analysis packages.

Proved Undeveloped Reserves

At December 31, 2012 and 2011, our proved undeveloped reserves were 3 prospects (the University 7 #1, the Morgan #1, and the Morgan #2) and none, respectively.

Oil and natural gas Production, Production Prices and Production Costs

The following table sets forth certain information regarding our production volume, and average sales and production costs for the periods indicated.

	Years Ended December 31,	
	2012	2011
Production:		
Oil (Bbls)	1,659	572
Natural gas (Mcf)	61,582	44,682
BOE	11,923	8,019
Average sales prices:		
Oil (per Bbl)	$ 83.98	$ 88.10
Natural gas (per Mcf)	$ 4.55	$ 6.59
BOE	$ 27.37	$ 38.06

Average production costs		
Lease operating expense	$ 126,131	$ 121,580
Production tax	$ 24,649	$ 39,156
BOE	$ 12.65	$ 20.04

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Drilling and Other Exploratory and Development Activities

The following table sets forth our drilling activity for the periods indicated.

	Years Ended December 31,			
	2012		2011	
	Gross	Net	Gross	Net
Exploratory Wells				
Productive	3.0	0.1	4.0	0.2
Dry	3.0	0.1	5.0	0.1
Developmental Wells				
Productive	2.0	0.1	-	-
Dry	-	-	-	-

During the period beginning January 1, 2013 and ending April 30, 2013, we participated in the drilling of 4 gross (.34 net) wells, all of which were completed.

Title to Properties

We believe that we have satisfactory title to substantially all of our active properties in accordance with standards generally accepted in the oil and natural gas industry. Our properties are subject to customary royalty interests, liens for current taxes and other burdens, which we believe do not materially interfere with the use of or affect the value of such properties. Prior to acquiring undeveloped properties, we perform a title investigation that is thorough but less vigorous than that conducted prior to drilling, which is consistent with standard practice in the oil and natural gas industry. Before we commence drilling operations, we conduct a thorough title examination and perform curative work with respect to significant defects before proceeding with operations. We have performed a thorough title examination with respect to substantially all of our active properties.

Item 3. LEGAL PROCEEDINGS

Cause No. 08-04-07047-CV; Oz Gas Corporation v. Remuda Operating Company, et al. v. Victory Energy Corporation.; In the 112th District Court of Crockett County, Texas.

Plaintiff Oz Gas Corporation sued Victory Energy Corporation and other parties for bad faith trespass, among other claims, regarding the drilling of two wells on lands that Oz ("OZ") claims title to Victory Energy Corporation has a 50% interest in one of the named wells involved in this lawsuit (that being well 155-2 on the Adams Baggett Ranch in Crockett County, Texas). The lawsuit was originally filed against other parties in April 2008, and Victory intervened in the case on November 18, 2009 to protect its interest in the 155-2 well.

The case was tried in February 2012. The Court found in favor of Oz and rendered verdict against Victory and the other defendants for the sum of $137,000. Victory Energy Corporation has appealed this decision to the 8th Court of Appeals in El Paso, Texas, and the case has been fully briefed and submitted.

Cause No. CV-47,230; James Capital Energy, LLC and Victory Energy Corporation v. Jim Dial, et al.; In the 142nd District Court of Midland County, Texas.

This lawsuit was filed in the 142nd District Court of Midland County, Texas on January 19, 2010 by James Capital Energy, LLC and Victory Energy Corporation against numerous parties for fraud, fraudulent inducement, and negligent misrepresentation, breach of contract, breach of fiduciary duty, trespass, conversion and a few other related causes of action. This lawsuit stems from an investment made by Victory for the purchase of six wells on the Adams Baggett Ranch.

On December 9, 2010, Victory was granted an interlocutory Default Judgment against Defendants Jim Dial, 1st Texas Natural Gas Company, Inc., Universal Energy Resources, Inc., Grifco International, Inc., and Precision Drilling & Exploration, Inc. The total judgment amounted to approximately $17.2 million. Recently Victory has added additional parties to this lawsuit. Discovery is ongoing in this case and no trial date has been set at this time.

Victory believes that it will be victorious against all the remaining Defendants in this case.

On October 20, 2011 Defendant Remuda filed a Motion to Consolidate and a Counterclaim against Victory. Remuda is seeking to consolidate this case with two other cases in which Remuda is the named Defendant. An objection to this motion was filed and the cases have not been consolidated. Additionally, we do not believe that the counterclaim made by Remuda has any legal merit.

Cause No. 10-09-07213; Perry Howell, et al. v. Charles Gary Garlitz, et al.; In the 112th District Court of Crockett County, Texas.

The above referenced lawsuit was filed in the 112th District Court of Crockett County, Texas on September 6, 2010. This lawsuit alleges that Cambrian Management, Ltd. and Victory Energy Corporation trespassed on lands owned by the Plaintiffs in the drilling of the Adams-Baggett 115-8 well in Crockett County, Texas.

Discovery is ongoing in this case and the case is set for trial in July 2014. Victory Energy Corporation believes that the claims have no merit and that it will prevail.

Cause No. D-1-GN-13-00044; Aurora Energy Partners and Victory Energy Corporation v. Crooked Oaks; In the 261st District Court of Travis County, Texas.

The Company has yet to collect an installment balance of $200,000 for the sale of its Jones County, Texas oil and gas interests in May of 2012. The Company believes it will ultimately recover this receivable, but has provided for it as an allowance for doubtful accounts, and has not included it in the net accounts receivable balance of the Company’s 2012 consolidated financial statements.

Item 4. MINE SAFETY DISCLOSURE

Not applicable.

PART II

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

Our common stock is currently quoted on the OTC Markets under the symbol "VYEY." The following table sets forth the high and low bid information for each quarter for the years ended December 31, 2012 and 2011. The information reflects prices between dealers, and does not include retail markup, markdown, or commission, and may not represent actual transactions.

Fiscal Year Ended December 31,	Period	Bid Prices High		Bid Prices Low	
2012	First Quarter	$	2.35	$	1.07
	Second Quarter	$	1.10	$	0.55
	Third Quarter	$	1.04	$	0.21
	Fourth Quarter	$	0.50	$	0.15
2011 (1)	First Quarter	$	1.10	$	0.48
	Second Quarter	$	2.00	$	0.85
	Third Quarter	$	2.90	$	1.25
	Fourth Quarter	$	1.75	$	0.95

(1) Reflects 50:1 reverse stock split that occurred January 12, 2012.

Holders

As of August 20, 2013, the high and low bid prices for our common stock on the OTC Market was $0.20 and $0.20, respectively. As of August 20, 2013, there were approximately 1432 holders of record of our common stock.

The transfer agent for our common stock is Transfer Online, Inc., 512 SE Salmon Street, Portland, Oregon 97214.

Dividend Policy

We have not paid any cash dividends on our common stock and do not expect to do so in the foreseeable future. We intend to apply our earnings, if any, in expanding our operations and related activities. The payment of cash dividends in the future will be at the discretion of the board of directors and will depend upon such factors as earnings levels, capital requirements, our financial condition and other factors deemed relevant by the board of directors.

Recent Sales of Unregistered Securities

The following securities were issued through December 31, 2012:

Period	Investment		Warrants
August	$	249,900	249,900
September	$	100,000	100,000
October	$	200,000	200,000
November	$	240,000	240,000
December	$	300,000	300,000

Totals	$ 1,089,900	1,089,900

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The following securities were issued through December 31, 2012 include the following:

Purpose	Granted	Outstanding
Board Services	120,000	120,000
Services	788,191	785,041
Employee Options	130,000	40,000
Private Placement	36,500	33,000
Totals	1,074,691	978,041

We did not purchase any of our own common stock during the year ended December 31, 2012.

Item 6. SELECTED FINANCIAL DATA

We are a “smaller reporting company” as defined by Rule 12b-2 under the Securities Exchange Act, and as such, are not required to provide the information required under this Item.

Item 7. MANAGEMENT DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. This section should be read in conjunction with our consolidated financial statements and the accompanying notes included elsewhere in this report. Statements in our discussion may be forward-looking statements. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause future production, revenues and expenses to differ materially from our expectations.

The following is management’s discussion and analysis of certain significant factors that have affected certain aspects of our financial position and results of operations during the periods included in the accompanying audited consolidated financial statements.

Forward Looking Statements

This Annual Report on Form 10-K contains forward-looking statements concerning our beliefs, plans, objectives, goals, expectations, anticipations, estimates, intentions, operations, future results and prospects, including statements that include the words “may,” “could,” “should,” “would,” “believe,” “expect,” “will,” “shall,” “anticipate,” “estimate,” “inten similar expressions. These forward-looking statements are based upon current expectations and are subject to risk, uncertainties and assumptions. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may vary materially from those anticipated, estimated, expected, projected, intended, committed or believed. We provide the following cautionary statement identifying important factors (some of which are beyond our control) which could cause the actual results or events to differ materially from those set forth in or implied by the forward-looking statements and related assumptions.

General Overview

The Company is an independent, growth oriented oil and natural gas company engaged in the acquisition, exploration, development and production of oil and natural gas properties, through its partnership with Navitus in Aurora. The Company’s objective is to create long-term shareholder value by increasing oil and natural gas reserves, improving financial returns (higher production volumes and lower costs), and managing the capital on its balance sheets.

We are geographically focused onshore, with a primary focus in the Permian Basin of Texas and southeast New Mexico. The Company leverages both internal capabilities and strategic industry relationships to acquire working interest positions in low-to-moderate risk oil and natural gas prospects. Our focus is on oil or liquid-rich gas projects with longer-life reserves that offer competitive finding and development (F&D) costs.

At the end of 2012, the Company held a working interest in 21 wells located in Texas and New Mexico, predominantly in the Permian Basin of West Texas.

Our primary company business objective is to grow proved reserves through new drilling and grow the value of those reserves by focusing on oil. For 2012, we achieved both a shift toward oil and increase in proved reserves through successful drilling. We also added properties large enough to offer new multi-well drilling opportunities in the future. These efforts created a year to year increase of 12% in proved reserves for 2012.

Our revenue, profitability, cash flow, oil and natural gas reserves value, future growth, and ability to borrow funds or obtain additional capital, as well as the carrying value of our properties, are substantially dependent on prevailing prices oil and natural gas. Historically, the markets for oil and natural gas have been volatile, and those markets are likely to continue to be volatile in the future. It is impossible to predict with certainty future prices for oil and natural gas, as such prices are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty, and a variety of additional factors beyond our control.

Going Concern

As presented in the consolidated financial statements, the Company has incurred a net loss of $6.7 million during the twelve months ended December 31, 2012, and losses are expected to continue in the near term. The accumulated deficit at December 31, 2012 was $35.2 million. The Company has been funding its operations through the sale of senior convertible 10% Senior Secured Convertible Debentures and from contributions made by its partners. Management anticipates that significant additional capital expenditures will be necessary to develop the Company’s oil and natural gas properties, which consist of proved and unproved reserves, some of which may be non-producing, before significant positive operating cash flows will be achieved.

Management is pursuing business partnering arrangements for the acquisition and development of its properties as well as debt and equity funding through private placements. Without outside investment from the sale of equity securities, debt financing or partnering with other oil and natural gas companies, operating activities and overhead expenses will be reduced to a pace that will match available operating cash flows.

The accompanying consolidated financial statements are prepared as if the Company will continue as a going concern. The consolidated financial statements do not contain adjustments, including adjustments to recorded assets and liabilities, which might be necessary if the Company were unable to continue as a going concern.

Results of Operations

Comparison of Year Ended December 31, 2012 to Year Ended December 31, 2011

Revenues: All of our revenue was derived from the sale of oil and natural gas. Revenues consist of the proceeds of sales, net of royalty, and gas transportation deductions. Our net revenue increased $21,204 or 7% to $326,384 for the twelve months ended December 31, 2012 from $305,180 for the twelve months ended December 31, 2011. The increase reflects primarily the increase in oil production revenues which increased $82,428 to $139,320 for the 12 months ended December 31, 2012, from $56,892 for the twelve months ended December 31, 2011.

Lease Operating Expenses: Lease operating expenses which includes the operating expenses of obtaining the oil and natural gas increased $4,551 or 4% to $126,131 for the twelve months ended December 31, 2012 from $121,580 for the twelve months ended December 31, 2011. The increase in lease operating expenses reflects an increase in the number of operating properties for the year ended December 31, 2012.

Dry Hole Costs: Dry Hole costs increased $54,678 or 100% for the twelve months ended December 31, 2012 from $0 for the twelve months ended December 31, 2011. The Company incurred dry holes costs in connection with the drilling of the Saddle Butte Prospect in Pecos County, Texas in 2012.

Production Taxes: Production taxes are charged at the well head for the production of gas and oil. Production taxes decreased $14,507 or 37% to $24,649 for the twelve months ended December 31, 2012 from $39,156 for the twelve months ended December 31, 2011. Although our revenues increased for 2012, our productions taxes were down because a larger percentage of our 2012 revenue came from oil sales which carry a lower tax of 4.6% versus 7.5% for natural gas.

Gain on Settlement with Former Officer: Gain on settlement with former officer decreased 100% for the twelve months ended December 31, 2012 from $404,624 for the twelve months ended December 31, 2011.

Exploration Expense: Exploration expenses decreased $293,009 or 52% to $266,514 for the twelve months ended December 31, 2012 from $559,523 for the twelve months ending December 31, 2011. The change is not considered meaningful and simply reflects the timing of expenses for exploration activities.

General and Administrative Expense: General and administrative expenses increased $729,171 or 35% to $2.8 million for the year ended December 31, 2012 from $2.1 million for the year ending December 31, 2011. The Cash G&A burn rate was higher for 2012 primarily due to additional headcount in Austin and non-recurring costs associated with the transfer of accounting services from California to Texas.

Depletion, Depreciation, and Accretion: Depletion and accretion expenses decreased $31,501 or 38% to $51,172 for the twelve months ended December 31, 2012 from $82,673 for the twelve months ended December 31, 2011. The decrease was due to the reduction in the amount of assets subject to depletion as a result of the sale of the Jones County/Atwood properties in May, 2012 and property impairments.

Impairment of Oil and Natural Gas Properties: Impairment of oil and natural gas properties increased $241,774 or 236% to $344,353 from $102,579 for the twelve months ended December 31, 2012. This is primarily due to our Uno Mas well which was deemed not commercial and a charge associated with the write-off of other undeveloped land costs in New Mexico.

Gain on Sale of Oil and Natural Gas Properties: Gain on sale of oil and natural gas properties increased $275,489 or 100% for the twelve months ended December 31, 2012. This is due to the sale of our Jones County property.

Interest Expense: Interest expense increased $2,194,941 or 121% to $4,009,979 for the twelve months ended December 31, 2012 from $1,815,038 for the twelve months ended December 31, 2011. Virtually all of the interest expense was associated with the Company’s 10% Senior Secured Convertible Debentures which were converted to common stock on February 29, 2012.

Income Taxes: There is no provision for income tax expenses recorded for either the twelve months ended December 31, 2012 or ended December 31, 2011 due to the expected net operating losses (NOL) of both years. The previously reported twelve months ended December 31, 2011 was restated to eliminate a tax benefit provision which was determined to not be realizable when applying ASC 740, based upon net realizable value evaluation. We had available Federal income tax net operating loss (“NOL”) carry forwards of 13,807,335 at December 31, 2012. Our NOL generally begins to expire in 2027.

The realization of future tax benefits is dependent on our ability to generate taxable income within the carry forward period. Given the Company’s history of net operating losses, management has determined that it is more-likely-than-not the Company will not be able to realize the tax benefit of the carry forwards. Current standards require that a valuation allowance thus be established when it is more likely than not that all or a portion of deferred tax assets will not be realized.

All tax benefits recognized in 2011 and 2012 due to the temporary difference in tax effect between the accounting and tax basis of the 10% Senior Secured Convertible Debentures were eliminated when the Debenture were converted to common stock on February 29, 2012.

Net Loss: Net losses increased 82% or $3,033,676 to $6,739,678 for the twelve months ended December 31, 2012 from a net loss of $3,706,002 for the twelve months ended December 31, 2011. This net loss should be viewed in light of the cash flow from operations discussed below.

During the year ended December 31, 2012, as with the year ended December 31, 2011, after adjusting for one-time gains, we did not generate positive cash flow from on-going operations. As a result, we funded our operations through the private sale of equity and debt securities, the issuance of our securities in exchange for services, and loans.

Liquidity and Capital Resources

Our cash and cash equivalents, total current assets, total assets, total current liabilities, and total liabilities as of December 31, 2012 as compared to December 31, 2011, are as follows:

	Dec. 31, 2012	Dec. 31, 2011
Cash	$ 158,165	$ 475,623
Total current assets	384,339	584,363
Total assets	1,859,981	1,626,795
Total current liabilities	273,209	689,383
Total liabilities	313,114	1,351,921

At December 31, 2012, we had a working capital surplus of $111,130 compared to a working capital deficit of $105,020 at December 31, 2011. Current liabilities decreased to $273,209 at December 31, 2012 from $689,383 at December 31, 2011 primarily due to a decrease of $322,634 in accounts payable, a decrease in accrued interest of $124,628, a decrease in the liability for unauthorized preferred stock of $22,881, and an increase of $53,969 in accrued liabilities.

The Company had a $6.7 million net loss, of which $5 million was in non-cash, resulting in $2.6 million net cash used by operating activities. This compares to cash used by operating activities for the twelve months ended December 31, 2011 of $2.0 million after the net loss for the period of $3.7 million was decreased by $2.2 million in non-cash charges and increased by $272,277 in changes to the working capital accounts.

Net cash used in investing activities, excluding exploration-related charges taken directly to income and prepaid receivables for drilling cost, for the twelve months ended December 31, 2012 was $516,533. This includes $8,925 for the drilling and completion of wells, $675,058 for the acquisition of land, $200,000 of proceeds from the sale of oil and natural gas properties, and $32,550 for the purchase of furniture and fixtures. This compares to $597,724 of net cash used by investing activities for the twelve month period ended December 31, 2011 which included $219,700 for the acquisition of producing wells, $369,695 for the drilling and completion of wells and $8,329 for the purchase of furniture and fixtures.

Net cash provided by financing activities for the twelve months ended December 31, 2012 was $2.8 million. Of this amount, $1.8 million came from the sale of 10% Senior Secured Convertible Debentures and $1.1 million came from contributions from Navitus. This compares to the $3.0 million in cash provided by financing activities during the twelve months ended December 31, 2011, of which $3.1 million came from the sale of 10% Senior Secured Convertible Debentures.

Three Months Ended March 31, 2011 Compared to the Three Months Ended March 31, 2010

Revenues: All of our revenue was derived from the sale of natural gas. Our revenues decreased $63,585 or 43% to $85,786 for the three months ended March 31, 2011 from $149,371 for the three months ended March 31, 2010. The decrease reflects both a decline in volume of gas sold to 11,675 MCF in the three months ended March 31, 2011 compared to 21,406 MCF for the three months ended March 31, 2010 and the decrease in the average natural gas price received of $7.35 per MCF for the three months ended March 31, 2011 compared to $6.98 for the three months ended March 31, 2010. The decline in gas production is attributable to the normal productivity decline that occurs with these types of wells over time.

Costs of Production: Our cost of production, including lease operating costs and production taxes increased $34,744 or 293% to $46,626 for the three months ended March 31, 2011 from $11,882 for the three months ended March 31, 2010. This increase is due to additional operating expenses and other one-time charges associated with on-going well production.

Exploration Expense: Exploration expense for the three month period ended March 31, 2011 was $73,132. This compares to no exploration expense for the three month period ended March 31, 2010. This increase in exploration expense reflects a higher level of exploration activities.

General and Administrative Expense: General and administrative expenses increased $456,868 or 288% to $615,296 for the three months ended March 31, 2011 from $158,428 for the three months ended March 31, 2010. The increase reflects a number of one-time charges including accounting, auditing, and legal expenses to bring the Company current on its SEC filings, the final settlement with the former officer of the Company, and the increase in salaries and expenses associated with the startup of the Austin office.

Depletion and Accretion: Depletion, accretion, and depreciation declined $12,781 or 51% to $12,202 for the three months ended March 31, 2011 from $24,983 for the three months ended March 31, 2010. The decrease was due to the lower amount of asset cost basis available to deplete following the impairment adjustment of 2010.

Gain on Settlement: On March 24, 2011, we entered into a comprehensive Settlement Agreement with Jon Fullenkamp in which Fullenkamp gave up his claim to several amounts reported by us as owing to him. The elimination of the claims were made to the consolidated financial statements in 2010 and reported in the both the 2010 Annual Report on Form 10-K and the 2010 Quarterly Reports on Forms 10-Q which had not been filed at the time of the settlement.

Interest Expense: Interest expense increased $204,860 or 2,483% to $213,112 for the three months ended March 31, 2011 from $8,252 for the three months ended March 31, 2010. Of this amount, $170,086 represents the amortization of the non-cash debt discount associated with the sale of the 10% Senior Secured Convertible Debentures and $43,026 represents the actual interest expense due on the 10% Senior Secured Convertible Debentures.

Income Taxes: There is no provision for income tax recorded for either the three months ended March 31, 2011 or for the three months ended March 31, 2010 due to the expected operating losses of both years. The original provision of an income tax benefit of $58,105 for the three months ended March 31, 2011 has been eliminated in restatement due to applying a net realizable value evaluation. We had available Federal income tax net operating loss (“NOL”) carry forwards of approximately $5.5 million at December 31, 2010. Our NOL generally begins to expire in 2027.

Net Income (Loss): We had a net loss of $363,567 for the three months ended March 31, 2011, due primarily to the one-time gain of $404,624 on the settlement with our former executive officer. For the three months ended March 31, 2010, we had a net loss of $76,934. During the three months ended March 31, 2011, as with the three months ended March 31, 2010, we did not generate positive cash flow from normal operations. As a result, we funded our operations through the private sale of equity and debt securities, the issuance of our securities in exchange for services, and loans.

Liquidity and Capital Resources

Our cash and cash equivalents, total current assets, total assets, total current liabilities, and total liabilities as of March 31, 2011 as compared to March 31, 2010, are as follows:

	March 31, 2011	March 31, 2010
Cash	$ 187,494	$ 48,600
Total current assets	280,806	182,784
Total assets	1,148,985	978,188
Total current liabilities	677,905	894,949
Total liabilities	1,002,611	929,926

At March 31, 2011, we had a working capital deficit of $397,099 compared to a working capital deficit of $712,165 at March 31, 2010. Current liabilities decreased to $677,905 at March 31, 2011 from $894,949 at March 31, 2010 primarily due to the conversion of short term notes payable and accrued interest due a related party to a 10% Senior Debenture.

Net cash used by operating activities for the three months ended March 31, 2011 totaled $505,505 after the cash used in the net loss of $363,567 was decreased by $201,248 in non-cash charges and increased by $109,724 in net increases in the working capital accounts. This compares to cash used by operating activities for the three months ended March 31, 2010 was $57,419 after the net loss for the period of $76,934.

Net cash used in investing activities for the three months ended March 31, 2011 was $213,868 of which $205,539 was used for drilling costs related to the new working interest acquired during the period and $8,329 was used in the purchase of furniture and equipment for the Austin office. There was no cash used in investing activities for the three months ended March 31, 2010.

Net cash provided by financing activities for the three months ended March 31, 2011 totaled $853,400 of which $910,000 came from sale of the 10% Senior Secured Convertible Debentures. Notes payable to a related party was paid off for $50,000 and the bank line of credit was paid down by $6,600. This compares to $83,943 in cash used in financing activities for the three month period ended March 31, 2010 of which $90,000 came from notes payable to a related party and $6,057 was used to pay down the bank line of credit.

Three Months Ended June 30, 2011 Compared to the Three Months Ended June 30, 2010

Revenues: All of our revenue was derived from the sale of oil and natural gas. Our revenues decreased $37,055 or 31% to $81,873 for the three months ended June 30, 2011 from $118,928 for the three months ended June 30, 2010. The decrease reflects a decline in volume of gas sold to 10,931 MCF in the three months ended June 30, 2011 compared to 21,032 MCF for the three months ended June 30, 2010 offset by an in increase in the average natural gas price received of $7.49 per MCF for the three months ended June 30, 2011 compared to $5.65 for the three months ended June 30, 2010. The decline in gas production is attributable to the normal productivity decline that occurs with these types of wells over time.

Costs of Production: Our cost of production, including lease operating costs and production taxes for the three months ended June 30, 2011 were $39,074 and were flat when compared to our production costs for the three month period ended June 30, 2010.

Exploration Expense: Exploration expense for the three month period ended June 30, 2011 was $58,451. This compares to no exploration expense for the three month period ended June 30, 2010. This increase in exploration expense reflects a higher level of exploration activity during the second quarter of 2011.

General and Administrative Expense: General and administrative expenses increased $228,468 or 122% to $415,242 for the three months ended June 30, 2011 from $186,774 for the three months ended June 30, 2010. The increase reflects a number of one-time charges including accounting, auditing, and legal expenses to bring the Company current on its SEC filings, and the increase in salaries and expenses associated with the opening of the Austin office in January 2011.

Depletion and Accretion: Depletion, accretion, and depreciation declined $6,581 or 26% to $18,402 for the three months ended June 30, 2011 from $24,983 for the three months ended June 30, 2010. The decrease was due to the lower amount of asset cost basis available to deplete following the impairment adjustment of 2010.

Interest Expense: Interest expense increased $954,434 to $965,303 for the three months ended June 30, 2011 from $10,869 for the three months ended June 30, 2010. Of this amount, $904,340 represents the amortization of the non-cash debt discount associated with the sale and conversion of the 10% Senior Secured Convertible Debentures and $60,963 represents the actual interest expense due on the 10% Senior Secured Convertible Debentures and the bank line of credit.

Income Taxes: There is no provision for income tax recorded for either the three months ended June 30, 2011 or for the three months ended June 30, 2010 due to the expected operating losses of both years. The original provision of an income tax benefit of $331,927 for the three months ended June 30, 2011 has been eliminated in restatement due to applying a net realizable value evaluation. We had available Federal income tax net operating loss (“NOL”) carry forwards of approximately $5.5 million at December 31, 2010. Our NOL generally begins to expire in 2027.

Net Loss: We had a net loss of $1.4 million for the three months ended June 30, 2011 compared to a net loss of $127,347 for the three months ended June 30, 2010. Of this loss, approximately $316,563 represents a net decrease in operating income and $954,434 represents increases in cash and non-cash financing interest costs. This net loss should be viewed in light of the cash flow from operations discussed below.

Six Months Ended June 30, 2011 Compared to the Six Months Ended June 30, 2010

Revenues: All of our revenue was derived from the sale of oil and natural gas. Our revenues decreased $100,620 or 38% to $167,679 for the six months ended June 30, 2011 from $268,299 for the six months ended June 30, 2010. The decrease reflects a decline in volume of gas sold to 22,606 MCF in the six months ended June 30, 2011 compared to 42,438 MCF for the six months ended June 30, 2010 offset by the increase in the average natural gas price received of $7.41 per MCF for the six months ended June 30, 2011 compared to $6.32 for the six months ended June 30, 2010. The decline in gas production is attributable to the normal productivity decline that occurs with these types of wells over time.

Costs of Production: Our cost of production, including lease operating costs and production taxes increased $33,914 or 65% to $85,700 for the six months ended June 30, 2011 from $51,786 for the six months ended June 30, 2010. This increase is due to additional operating expenses and other one-time charges associated with on-going well production.

Exploration Expense: Exploration expense for the six month period ended June 30, 2011 was $117,923. This compares to no exploration expense for the same six month period of 2010. This increase in exploration expense reflects a higher level of exploration activity during the first six months of 2011.

General and Administrative Expense: General and administrative expenses increased $698,996 or 202% to $1,044,198 for the six months ended June 30, 2011 from $345,202 for the six months ended June 30, 2010. The increase reflects a number of one-time charges including accounting, auditing, and legal expenses to bring the Company current on its SEC filings, the legal cost related to the final settlement with the former officer of the Company, and the increase in salaries and expenses associated with the operations of the Austin office.

Depletion and Accretion: Depletion, accretion, and depreciation declined $19,362 or 39% to $30,604 for the six months ended June 30, 2011 from $49,966 for the six months ended June 30, 2010. The decrease was due to the lower amount of asset cost basis available to deplete following the impairment adjustment of 2010.

Gain on Settlement: On March 24, 2011, we entered into a comprehensive Settlement Agreement with Jon Fullenkamp in which Fullenkamp gave up his claim to several amounts reported by us as owing to him. The elimination of the claims were made to the consolidated financial statements in 2010 and reported in the both the 2010 Annual Report on Form 10-K and the 2010 Quarterly Reports on Forms 10-Q which had not been filed at the time of the settlement.

Interest Expense: Interest expense increased $1.2 million to $1.2 million for the six months ended June 30, 2011 from $19,121 for the six months ended June 30, 2010. Of this amount, $1.1 million represents the amortization of the non-cash debt discount associated with the sale and conversion of the 10% Senior Secured Convertible Debentures and $103,989 represents the actual interest expense due on the 10% Senior Secured Convertible Debentures.

Income Taxes: There is no provision for income tax recorded for either the six months ended June 30, 2011 or for the six months ended June 30, 2010 due to the expected operating losses of both years. The original provision of an income tax benefit of $390,032 for the six months ended June 30, 2011 has been eliminated in restatement due to applying a net realizable value evaluation. We had available Federal income tax net operating loss ("NOL") carry forwards of approximately $5.5 million at December 31, 2010. Our NOL generally begins to expire in 2025.

Net Income (Loss): We had a net loss of $1.7 million for the six months ended June 30, 2011. Of this amount, there was a one-time gain of $404,624 on the settlement with our former executive officer.

For the six months ended June 30, 2010, we had a net loss of $191,271. This net loss should be viewed in light of the cash flow from operations discussed below.

During the six months ended June 30, 2011, as with the six months ended June 30, 2010, we did not generate positive cash flow from normal operations. As a result, we funded our operations through the private sale of equity and debt securities, the issuance of our securities in exchange for services, and loans.

Liquidity and Capital Resources

Our cash and cash equivalents, total current assets, total assets, total current liabilities, and total liabilities as of June 30, 2011 as compared to June 30, 2010, are as follows:

	June 30, 2011	June 30, 2010
Cash	$ 467,712	$ 68,838
Total current assets	553,366	172,316
Total assets	1,505,771	942,737
Total current liabilities	554,779	999,770
Total liabilities	671,325	1,034,747

At June 30, 2011, we had a working capital deficit of $1,413 compared to a working capital deficit of $827,454 at June 30, 2010. Current liabilities decreased to $554,779 at June 30, 2011 from $999,770 at June 30, 2010 primarily due to the conversion of short term notes payable and accrued interest due a related party to a 10% Senior Secured Debenture.

Net cash used in operating activities for the six months ended June 30, 2011 totaled $.9 million after the cash used in the net loss of $1.7 million was decreased by $750,198 in non-cash charges and increased by $85,267 in net increases in the working capital accounts. This compares to cash used in operating activities for the six months ended June 30, 2010 of $66,533 after the net income for the period of $191,271 was reduced by $348,627 in non- cash charges and offset by $75,247 in changes to the working capital accounts.

Net cash used in investing activities for the six months ended June 30, 2011 was $316,496 of which $308,167 was used for drilling costs related to the new working interest acquired during the period and $8,329 was used in the purchase of furniture and equipment for the Austin office.

Net cash provided by financing activities for the six months ended June 30, 2011 was $1.7 million. Of this amount, $1.8 million came from the sale of 10% Senior Secured Convertible Debentures offset by $56,180 in payments on loans. This compares to $113,295 in cash was provided by financing activities during the six months ended June 30, 2011 of which $125,000 came from a related party loan and $11,705 was used to pay down loans.

Three Months Ended September 30, 2011 Compared to the Three Months Ended September 30, 2010

Revenues: All of our revenue was derived from the sale of oil and natural gas. Our revenues decreased $18,560 or 17% to $90,570 for the three months ended September 30, 2011 from $109,130 for the three months ended September 30, 2010. The decrease reflects the sale of 111 barrels of oil at a weighted average price of $87.75 per barrel. There were no sales of oil in the three months ended September 30, 2010. Before offsets for minority ownership, the decrease also reflects the sale of 16,688 MCF of natural gas at a weighted average price of $4.84 per MCF in the three months ended September 30, 2011 compared to 18,256 MCF of natural gas sold in the three months ending September 30, 2010 at an average price of $5.91 per MCF. The decline in physical gas production is attributable to the normal productivity decline that occurs with these types of wells over time.

Costs of Production: Our cost of production, including lease operating costs and production taxes decreased $7,605 or 20% to $31,213 for the three months ended September 30, 2011 from $38,818 for the three months ended September 30, 2010. This decrease is due to one-time charges associated with on-going well production that are included in our cost of production for the second quarter 2010.

Exploration Expense: Exploration expense for the three month period ended September 30, 2011 was $113,301. This compares to no exploration expense for the same three month period of 2010. This increase in exploration expense reflects a higher level of exploration activity during the third quarter of 2011.

General and Administrative Expense: General and administrative expenses increased $222,149 or 100% to $445,091 for the three months ended September 30, 2011 from $222,942 for the three months ended September 30, 2010. For the most part, the increase reflects two additional officers hired in 2011 including the associated payroll taxes and benefits, the fair value of options granted the new officers in the current period, the operations of the Austin office opened in 2011, the services of an investor relations firm, and the fair value of the non-cash director's compensation earned in the period.

Depletion and Accretion: Depletion, accretion, and depreciation declined $14,817 or 59% to $10,166 for the three months ended September 30, 2011 from $24,983 for the three months ended September 30, 2010. The decrease was due to the lower amount of asset cost basis available to deplete following the impairment adjustment of 2010.

Interest Expense: Interest expense increased $321,628 to $332,604 for the three months ended September 30, 2011 from $10,976 for the three months ended September 30, 2010. For the three months ended September 30, 2011, $297,418 represents the amortization of the non-cash debt discount associated with the sale of the 10% Senior Secured Convertible Debentures and $35,186 represents the actual interest expense accrued on the 10% Senior Secured Convertible Debentures outstanding.

Income Taxes: There is no provision for income tax recorded for either the three months ended September 30, 2011 or for the three months ended September 30, 2010 due to the expected operating losses of both years. The original provision of an income tax benefit of $76,671 for the three months ended September 30, 2011 has been eliminated in restatement due to applying a net realizable value evaluation. We had available Federal income tax net operating loss ("NOL") carry forwards of approximately $5.5 million at December 31, 2010. Our NOL generally begins to expire in 2027.

Net Loss: We had a net loss of $820,048 for the three months ended September 30, 2011 compared to a net loss of $175,403 for the three months ended September 30, 2010. This net loss should be viewed in light of the cash flow from operations discussed below.

Nine Months Ended September 30, 2011 Compared to the Nine Months Ended September 30, 2010

Revenues: All of our revenue was derived from the sale of oil and natural gas. Our revenues decreased $123,635 or 33% to $253,794 for the nine months ended September 30, 2011 from $377,429 for the nine months ended September 30, 2010. Oil revenues for the nine months ended September 30, 2011 reflect the sale of 168 barrels of oil at a weighted average price of $90.31 per barrel. There were no sales of oil in the nine months ended September 30, 2010. Before offsets minority ownership, gas revenues reflect the sale of 50,762 MCF of gas at a weighted average price of $4.70 per MCF for the nine months ended September 30, 2011 compared to the sale of 60,695 MCF of natural gas sold at $6.22 per MCF for the nine month period ended September 30, 2010. The decline in gas production is attributable to the normal productivity decline that occurs with these types of wells over time.

Costs of Production: Our cost of production, including lease operating costs and production taxes increased $21,874 or 24% to $112,478 for the nine months ended September 30, 2011 from $90,604 for the nine months ended September 30, 2010. This increase is due to additional operating expenses and other one-time charges associated with on-going well production.

Exploration Expense: Exploration expense for the nine month period ended September 30, 2011 was $175,574. This compares to no exploration expense for the same nine month period of 2010. This increase in exploration expense reflects a higher level of exploration activity during the first nine months of 2011.

General and Administrative Expense: General and administrative expenses increased $1,152,237 or 202% to $1,544,897 for the nine months ended September 30, 2011 from $568,144 for the nine months ended September 30, 2010. The increase reflects a number of one-time charges including accounting, auditing, and legal expenses to bring the Company current on its SEC filings, the legal cost related to the final settlement with the former officer of the Company, as well as the two additional officers hired in 2011 including the associated payroll taxes and benefits, the fair value of options granted the new officers in the current period, the operations of the Austin office opened in 2011, the services of an investor relations firm, and the fair value of the non-cash director's compensation earned in the period.

Depletion and Accretion: Depletion, accretion, and depreciation declined $34,179 or 46% to $40,770 for the nine months ended September 30, 2011 from $74,949 for the nine months ended September 30, 2010. The decrease was due to the lower amount of asset cost basis available to deplete following the impairment adjustment of 2010.

Gain on Settlement: On March 24, 2011, we entered into a comprehensive Settlement Agreement with Jon Fullenkamp in which Fullenkamp gave up his claim to several amounts reported by us as owing to him. The elimination of the claims were made to the consolidated financial statements in 2010 and reported in both the 2010 Annual Report on Form 10-K and the 2010 Quarterly Reports on Forms 10-Q which had not been filed at the time of the settlement.

Interest Expense: Interest expense increased $1.5 million to $1.5 million for the nine months ended September 30, 2011 from $30,097 for the nine months ended September 30, 2010. Of this amount, $1.4 million represents the amortization of the non-cash debt discount associated with the sale and conversion of the 10% Senior Secured Convertible Debentures and $139,175 represents the actual interest expense due on the 10% Senior Secured Convertible Debentures.

Income Taxes: There is no provision for income tax recorded for either the nine months ended September 30, 2011 or for the nine months ended September 30, 2010 due to the expected operating losses of both years. The original provision of an income tax benefit of $466,703 for the nine months ended September 30, 2011 has been eliminated in restatement due to applying a net realizable value evaluation. We had available Federal income tax net operating loss (“NOL”) carry forwards of approximately $5.5 million at December 31, 2010. Our NOL generally begins to expire in 2025.

Net Income (Loss): We had a net loss of $2.6 million for the nine months ended September 30, 2011. This net loss should be viewed in light of the cash flow from operations discussed below, which included a one-time gain of $404,624 on the settlement with our former executive officer.

For the nine months ended September 30, 2010, we had a net loss of $379,684. This net income should be viewed in light of the cash flow from operations discussed below.

During the nine months ended September 30, 2011, as with the nine months ended September 30, 2010, we did not generate positive cash flow from normal operations. As a result, we funded our operations through the private sale of equity and debt securities, the issuance of our securities in exchange for services, and loans.

Liquidity and Capital Resources

Our cash and cash equivalents, total current assets, total assets, total current liabilities, and total liabilities as of September 30, 2011 as compared to September 30, 2010, are as follows:

	Sept. 30, 2011	Sept. 30, 2010
Cash	$ 223,231	$ 69,038
Total current assets	345,455	151,836
Total assets	1,397,094	897,274
Total current liabilities	330,192	1,140,286
Total liabilities	744,156	1,175,263

At September 30, 2011, we had working capital of $15,263 compared to a working capital deficit of $988,450 at September 30, 2010. Current liabilities decreased to $330,192 at September 30, 2011 from $1,140,286 at September 30, 2010 primarily due to the payoff of the amount due the bank, the amount due a related party, and the conversion of preferred stock to common stock.

Net cash used in operating activities for the nine months ended September 30, 2011 totaled $1.4 million after the net loss of $2.6 million was decreased by $1.2 million in non-cash charges offset by $113,398 in changes to the working capital accounts. This compares to cash used in operating activities for the nine months ended September 30, 2010 of $96,733 after the net loss for the period of $379,684 was decreased by $321,034 in non-cash charges and offset by $206,043 in changes to the working capital accounts.

Net cash used in investing activities for the nine months ended September 30, 2011 was $425,896 of which $417,567 was used for drilling costs related to the new working interest acquired during the period and $8,329 was used in the purchase of furniture and equipment for the Austin office.

Net cash provided by financing activities for the nine months ended September 30, 2011 was $2.1 million. Of this amount, $2.3 million came from the sale of 10% Senior Secured Convertible Debentures offset by $68,667 to retire the bank loan and the $50,000 payoff of amounts due related parties. This compares to $143,695 in cash was provided by financing activities during the nine months ended September 30, 2011 of which $162,000 came from a related party loan and $18,305 was used to pay down the bank loan.

Three Months Ended March 31, 2012 Compared to the Three Months Ended March 31, 2011

Revenues: All of our revenue was derived from the sale of oil and natural gas. Our revenues decreased $21,821 or 25% to $63,965 for the three months ended March 31, 2012 from $85,786 for the three months ended March 31, 2011. The decrease reflects a decline in the amount of natural gas sold to 10,386 Mcf at $4.52 per Mcf for the three months ending March 31, 2012 from 11,675 Mcf sold at $6.49 per Mcf in the three months ended March 31, 2011. The decline in physical gas production is attributable to the normal productivity decline that occurs with these types of wells over time. During the three months ended March 31, 2012, we also sold 184 barrels of oil at $92.24 per barrel. There were no sales of oil in the three months ended March 31, 2011.

Lease Operating Expenses: Our cost of production includes a one-time credit of $35,157 received from an Operator that had received the credit from one of its vendors. Had this credit not been recognized in the period, our cost of production would have been approximately $21,002 for the three months ending March 31, 2012 which would have represented a decrease of $20,496 or 49% from $41,499 for the three months ended March 31, 2011.

Production Taxes: Production taxes increased $1,352 or 26% to $6,479 for the three months ended March 31, 2012 from $5,127 for the three months ended March 31, 2011. The change is not considered meaningful and reflects the timing of the calculation and payment of production taxes.

Exploration Expense: Exploration expense increased $23,735 or 32.5% to $96,867 for the three months ended March 31, 2012 from $73,132 for the three months ended March 31, 2011. This increase reflects the higher tempo of exploration activities as the Company had only just hired a full time exploration officer employee in the three months ended March 31, 2011.

General and Administrative Expense: General and administrative expenses increased $49,538 or 8.3% to $645,875 for the three months ended March 31, 2012 from $596,337 for the three months ended March 31, 2011. For the most part, the increase reflects the addition of a new chief financial officer, ongoing investor relations activities, and outside management consulting services which were not part of general and administrative expense in the three months ended March 31, 2011.

General and Administrative Expense – non cash: General and administrative non-cash expenses increased $316,890 to $335,850 for the three months ended March 31, 2012 from $18,960 for the three months ended March 31, 2011. The increase reflects the non-cash charges related to the issuance of warrants to board members for their service as members of the board, additional warrants to a related party to serve as general counsel of the Company, warrants to a management consultant for services in that capacity, employee stock options to the new Chief Financial Officer, and the amortization of employee stock options as such options vest. Such non-cash compensation totaled $18,960 in the three months ended March 31, 2011 in warrants to the board members for their service as members of the board.

Depletion and Accretion: Depletion, accretion, and depreciation increased $6,607 or 54% to $18,809 for the three months ended March 31, 2012 from $12,202 for the three months ended March 31, 2011. The increase is due to the additional depletion of the operating oil wells in 2012 which the company did not have in the three months ending March 31, 2011.

Interest Expense: Interest expense increased $3.8 million to $4.0 million for the three months ended March 31, 2012 from $213,112 for the three months ended March 31, 2011. For the three months ended March 31, 2012, $265,460 represents the amortization of the non-cash debt discount associated with the sale of the outstanding 10% Senior Secured Convertible Debentures from January 1, 2012 up to the point where the 10% Senior Secured Convertible Debentures were converted to common stock on February 29, 2012, $3.7 million represents the recognition of the remaining non-cash debt discount associated with the conversion of all the outstanding 10% Senior Secured

Convertible Debentures to common stock on February 29, 2012, and $56,782, for the most part, represents the actual interest expense accrued on the 10% Senior Secured Convertible Debentures outstanding until their conversion on February 29, 2012.

Income Taxes: There is no provision for income tax recorded for either the three months ended March 31, 2012 or for the three months ended March 31, 2011 due to the expected operating losses of both years. The original provision of an income tax benefit of $58,105 for the three months ended March 31, 2011 has been eliminated in restatement due to applying a net realizable value evaluation. We had available Federal income tax net operating loss (“NOL”) carry forwards of approximately $12,960,120 at December 31, 2011. Our NOL generally begins to expire in 2027.

Net Loss: We had a net loss of $5.0 million for the three months ended March 31, 2012 compared to a net loss of $363,567 for the three months ended March 31, 2011. For the three months ended March 31, 2012 approximately $4.3 million of this loss was related to the non-cash charges related to the debt discount on the 10% Senior Secured Convertible Debentures which were converted to common stock on February 29, 2012 and to non-cash compensation awards to individuals for board service, employee stock options, and other management and consulting services. This net loss should be viewed in light of the cash flow from operations discussed below.

Liquidity and Capital Resources

Our cash and cash equivalents, total current assets, total assets, total current liabilities, and total liabilities as of March 31, 2012 as compared to March 31, 2011, are as follows:

	March 31, 2012	March 31, 2011
Cash	$ 872,367	$ 187,494
Total current assets	1,034,470	280,806
Total assets	2,645,888	1,148,985
Total current liabilities	423,312	677,905
Total liabilities	453,316	1,002,611

At March 31, 2012, we had working capital of $611,158 compared to a working capital deficit of $397,099 at March 31, 2011. Current liabilities decreased to $423,312 at March 31, 2012 from $677,905 at March 31, 2011 primarily due to the payoff of the amount due the bank, the amount due a related party, the conversion of unauthorized preferred stock to common stock, and the conversion of accrued interest to common stock.

Net cash used in operating activities for the three months ended March 31, 2012 totaled $830,461 after the net loss of $5.0 million was decreased by $4.3 million in non-cash charges and offset by $112,703 in changes to the working capital accounts. This compares to cash used in operating activities for the three months ended March 31, 2011 of $563,610 after the net loss for the period of $816,477 was decreased by $201,248 in non-cash charges and $109,724 in changes to the working capital accounts.

Net cash used in investing activities for the three months ended March 31, 2012 was $587,795 of which $82,795 was for drilling and related costs for exploration efforts and $505,000 was used to acquire land for drilling. This compares to $205,539 in drilling costs and $8,329 in purchases of furniture and fixtures for the then new Austin, Texas office during the three months ended March 31, 2011.

Net cash provided by financing activities for the three months ended March 31, 2012 was $1.8 million of which $1.7 million came from the sale of the Company’s 10% Senior Secured Convertible Debentures. This compares to $853,400 provided by financing activities during the three months ended March 31, 2011 of which $910,000 came from the sale of the Company’s 10% Senior Secured Convertible Debentures, $6,600 was used to pay down the bank line of credit and $50,000 was used to pay off a note due a related party.

Three Months Ended June 30, 2012 compared to the Three Months Ended June 30, 2011

Revenues: All of our revenue was derived from the sale of oil and natural gas. Our revenues decreased $13,722 or 16.8% to $68,151 for the three months ended June 30, 2012 from $81,873 for the three months ended June 30, 2011. The decrease primarily reflects a decline in the price and volume of natural gas sold to $3.51 per Mcf for the 10,549 Mcf of gas sold for the three months ending June 30, 2012 from $6.51 per Mcf for the 10,931 Mcf of gas sold in the three months ended June 30, 2011. The decline in physical gas production is attributable to the normal productivity decline that occurs with these types of wells over time. During the three months ended June 30, 2012, we also sold 289 barrels of oil at $90.90 per barrel. There were no sales of oil in the three months ended June 30, 2011.

Lease Operating Expenses: Our cost of production increased $27,063 or 89% to $57,565 for the three months ended June 30, 2012 from $30,502 for the three months ended June 30, 2011. The increase in lease operating expenses reflects an increase in the number of operating properties in the three months ended June 30, 2012 compared to the three months ended June 30, 2011.

Production Taxes: Production taxes decreased $2,901 or 33.8% to $5,671 for the three months ended June 30, 2012 from $8,572 for the three months ended June 30, 2011. The change is not considered meaningful and reflects the timing of the calculation and payment of production taxes.

Exploration Expense: Exploration expense increased $1,753 or 3.0% to $60,204 for the three months ended June 30, 2012 from $58,451 for the three months ended June 30, 2011. The change is not considered meaningful and simply reflects the timing of expenses for exploration activities.

Exploration Expense – non cash: Exploration non-cash expense increased $10,125 for the three months ended June 30, 2012 from $0 for the three months ended June 30, 2011. This increase reflects the vesting of exploration-dedicated employee stock options during the three months ended June 30, 2012. There were no stock options outstanding during the three months ending June 30, 2011.

General and Administrative Expense: General and administrative expenses decreased $71,212 or 17.8% to $327,790 for the three months ended June 30, 2012 from $399,002 for the three months ended June 30, 2011. For the most part, the decrease reflects the reduction in professional and consulting fees with the consolidation of the Company's operations in Austin, Texas.

General and Administrative Expense – non cash: General and administrative non-cash expenses increased $241,870 to $258,110 for the three months ended June 30, 2012 from $16,240 for the three months ended June 30, 2011. The increase reflects the non-cash charges related to the grant of employee stock options and the amortization of previous of stock options as they vest over time and the cost of warrants granted to one affiliate and two non-affiliates of the Company for special consulting assistance in certain undertakings of the Company. Such non-cash compensation totaled $18,960 in the three months ended June 30, 2011 for warrants to the board members for their service as members of the board.

Depletion and Accretion: Depletion, accretion, and depreciation decreased $5,130 or 27.9% to $13,272 for the three months ended June 30, 2012 from $18,402 for the three months ended June 30, 2011. The decrease is due to the reduction in amount of assets subject to depletion as a result of the sale of the Jones County/Atwood properties in May, 2012.

Gain on Sale of Assets: On May 10, 2012, the Company sold its interests in the Jones County Oil Play and the Atwood Secondary Oil Recovery project for $400,000 in cash payable in two even installments in May and July, 2012. The sale resulted in a one-time pre-tax gain of $268,169.

Interest Expense: Interest expense decreased $964,985 to $318 for the three months ended June 30, 2012 from $965,303 for the three months ended June 30, 2011. The decrease was due to the conversion of the 10% Senior Secured Convertible Debentures to the Company's common stock on February 29, 2012 which eliminated the source of the interest expense. The $318 in interest expense results from the financing associated with one of the Company's insurance policies.

Income Taxes: There is no provision for income tax recorded for either the three months ended June 30, 2012 or for the three months ended June 30, 2011 due to the expected operating losses of both years. The original provision of an income tax benefit of $396,735 for the three months ended June 30, 2011 has been eliminated in restatement due to applying a net realizable value evaluation. We had available Federal income tax net operating loss ("NOL") carry forwards of 12,960,120 at December 31, 2011. Our NOL generally begin to expire in 2027.

Net Loss: We had a net loss of $497,678 for the three months ended June 30, 2012 compared to a net loss of $1.4 million for the three months ended June 30, 2011. This net loss for the three months ended June 30, 2012 should be viewed in light of the cash flow from operations discussed below.

Six Months Ended June 30, 2012 Compared to the Six Months Ended June 30, 2011

Revenues: All of our revenue was derived from the sale of oil and natural gas. Our revenues decreased $35,541 or 21.2% to $132,118 for the six months ended June 30, 2012 from $167,659 for the six months ended June 30, 2011. The decrease reflects a decline in the price and volume of natural gas sold to $4.14 per Mcf for the 20,892 Mcf of gas sold for the six months ending June 30, 2012 from $6.70 per Mcf for the 22,606 Mcf of gas sold in the six months ended June 30, 2011. The decline in physical gas production is attributable to the normal productivity decline that occurs with these types of wells over time. During the six months ended June 30, 2012, we also sold 492 barrels of oil at $92.88 per barrel. There were no sales of oil in the six months ended June 30, 2011.

Lease Operating Expenses: Our cost of production decreased $28,590 or 39.7% to $43,411 for the six months ended June 30, 2012 from $72,001 for the six months ended June 30, 2011. The decrease in lease operating expenses resulted from a large one-time credit from a 2011 sub-contractor billing error in favor of one of our field operators during the three months ended March 31, 2012. Had this credit not been received, our cost of production for the six months ended June 30, 2012 would have been $61,055. This would have been a decrease of $10,946 from $72,001 for the six month period ended June 30, 2011. This decrease is not meaningful and reflects the timing of operator activities on the properties. There was an increase in the number of oil and natural gas properties during the six months ended June 30, 2012 compared to the six months ended June 30, 2012, notwithstanding our sale of the Jones County Oil Play and the Atwood Secondary Oil Recovery project in May, 2012.

Production Taxes: Production taxes decreased $1,549 or 11.3% to $12,150 for the six months ended June 30, 2012 from $13,699 for the six months ended June 30, 2011. The change is not considered meaningful and reflects the timing of the calculation and payment of production taxes.

Exploration Expense: Exploration expense increased $29,023 or 24.6% to $146,946 for the six months ended June 30, 2012 from $117,923 for the six months ended June 30, 2011. The increase reflects the higher overall level of exploration activities for the six months ended June 30, 2012 compared to the six month period ended June 30, 2011.

Exploration Expense – non cash: Exploration non-cash expense increased $20,250 for the six months ended June 30, 2012 from $0 for the three months ended June 30, 2011. This increase reflects the vesting of exploration-dedicated employee stock options during the six months ended June 30, 2012. During the six months ended June 30, 2011, there were no option grants outstanding.

General and Administrative Expense: General and administrative expenses decreased $35,333 or 3.5% to $973,665 for the six months ended June 30, 2012 from $1,008,998 for the six months ended June 30, 2011. For the most part, the decrease reflects the net effect of the addition of a new chief financial officer, ongoing investor relations activities, and outside management consulting services which were not part of general and administrative expense in the six months ended June 30, 2011 offset by lower audit, accounting, and legal fees associated with the extensive restatement and catch up effort to bring the Company current on its SEC filings undertaken as well as the legal settlement with a former officer of the Company during the six months ended June 30, 2011.

General and Administrative Expense – non cash: General and administrative non-cash expenses increased $558,760 to $593,960 for the six months ended June 30, 2012 from $35,200 for the six months ended June 30, 2011. The increase reflects the non-cash charges related to grants of non-qualified stock options to employees and offices of the Company and the amortization of previous of stock option as they vest over time, the cost of warrants granted to affiliates and non-affiliates is of the Company for special consulting assistance in certain undertakings of the Company, and warrants granted to a related party to serve as general counsel of the Company. Such non-cash compensation totaled $35,200 in the six months ended June 30, 2011 for warrants to the board members for their service as members of the board.

Depletion and Accretion: Depletion, accretion, and depreciation increased $1,477 or 4.8% to $32,081 for the six months ended June 30, 2012 from $30,604 for the six months ended June 30, 2011. The increase is not considered meaningful and due to the additional depletion of the operating oil wells in early 2012 which the Company did not have in the six months ending June 30, 2011 which was somewhat offset by the reduction in amount of assets subject to depletion as a result of the sale of the Jones County/Atwood properties in May, 2012.

Gain on Sale of Assets: On May 10, 2012, the Company sold its interests in the Jones County Oil Play and the Atwood Secondary Oil Recovery project for $400,000 in cash payable in two even installments in May and July, 2012. The sale resulted in a one-time gain of $268,169.

Interest Expense: Interest expense increased $2.8 million to $4.0 million for the six months ended June 30, 2012 from $1.2 million for the six months ended June 30, 2011. For the six months ended June 30, 2012, $265,460 represents the amortization of the non-cash debt discount associated with the sale of the 10% Senior Secured Convertible Debentures from January 1, 2012 up to the point where the 10% Senior Secured Convertible Debentures were converted to common stock on February 29, 2012, $3.7 million represents the recognition of the remaining non-cash debt discount associated with the conversion of all the outstanding 10% Senior Secured Convertible Debentures to common stock on February 29, 2012, and $56,782, for the most part, represents the actual interest expense accrued on the 10% Senior Secured Convertible Debentures outstanding until the conversion of the 10% Senior Secured Convertible Debentures on February 29, 2012.

Income Taxes: There is no provision for income tax recorded for either the six months ended June 30, 2012 or for the six months ended June 30, 2011 due to the expected operating losses of both years. The original provision of an income tax benefit of $390,032 for the six months ended June 30, 2011 has been eliminated in restatement due to applying a net realizable value evaluation. We had available NOL carry forwards of 12,960,120 at December 31, 2011. Our NOL generally begins to expire in 2027.

Net Loss: We had a net loss of $5.5 million for the six months ended June 30, 2012 compared to a net loss of $1.7 million for the six months ended June 30, 2011. The net loss was reduced by the gain on the sale of assets of $268,169. For the six months ended June 30, 2012 approximately $4.5 million of this loss was related to the non-cash charges related to the debt discount on the 10% Senior Secured Convertible Debentures which were converted to common stock on February 29, 2012 and to non-cash compensation awards to individuals for board service, employee stock options, and other management and consulting services. This net loss should be viewed in light of the cash flow from operations discussed below.

Liquidity and Capital Resources

Our cash, total current assets, total assets, total current liabilities, and total liabilities as of June 30, 2012 as compared to June 30, 2011, are as follows:

	June 30, 2012	June 30, 2011
Cash	$ 320,015	$ 467,712
Total current assets	590,258	553,366
Total assets	2,337,180	1,505,771
Total current liabilities	215,872	554,779
Total liabilities	245,876	671,325

At June 30, 2012, we had working capital of $374,386 compared to a working capital deficit of $1,413 at June 30, 2011. Current liabilities decreased to $215,872 at June 30, 2012 from $554,779 at June 30, 2011 primarily due to the payoff of the amount due a bank, the amount due a related party, the conversion of unauthorized preferred stock to common stock, and the conversion of accrued interest to common stock.

Net cash used in operating activities for the six months ended June 30, 2012 $1.5 million after the net loss of $5.4 million was decreased by $4.3 million in non-cash charges and offset by $197,857 in changes to the working capital accounts. This compares to cash used in operating activities for the six months ended June 30, 2011 of $1.0 million after the net loss for the period of $1.7 million was decreased by $750,198 in non-cash charges and $85,267 in changes to the working capital accounts.

Net cash used in investing activities for the six months ended June 30, 2012 was $875,946 of which $159,494 was for drilling and related costs for exploration efforts, $706,093 was used to acquire land and rights to land for drilling, and $10,359 was used to purchase furniture and fixtures for the Austin, Texas office. This compares to $308,167 in drilling costs and $8,329 in purchases of furniture and fixtures for the then new Austin, Texas office during the six months ended June 30, 2011. $200,000 came from the sale of the Company's investment in the Jones County/Atwood properties.

Net cash provided by financing activities for the six months ended June 30, 2012 was $2.2 million of which $1.8 million came from the sale of the 10% Senior Secured Convertible Debentures and $4,350 came from the exercise of warrants. This compares to $1.7 million provided by financing activities during the six months ended June 30, 2011 of which $1.8 million came from the sale of the 10% Senior Secured Convertible Debentures while $6,180 was used to pay down a bank line of credit and $50,000 was used to pay off a note due a related party.

Three Months Ended September 30, 2012 compared to the Three Months Ended September 30, 2011

Revenues: All of our revenue was derived from the sale of oil and natural gas. Our revenues decreased $13,535 or 14.9% to $77,035 for the three months ended September 30, 2012 from $90,570 for the three months ended September 30, 2011. The decrease reflects a decline in sale of natural gas during the three months ending September 30, 2012 from the three months ended September 30, 2011. The decline in gas production is attributable to the normal productivity decline that occurs with these types of wells over time.

Lease Operating Expenses: Our cost of production increased $2,901 or 15.8% to $21,285 for the three months ended September 30, 2012 from $18,384 for the three months ended September 30, 2011. The increase in lease operating expenses reflects an increase in the number of operating properties in the three months ended September 30, 2012 compared to the three months ended September 30, 2011.

Production Taxes: Production taxes decreased $9,199 or 71.7% to $3,630 for the three months ended September 30, 2012 from $12,829 for the three months ended September 30, 2011. This results primarily from the decline in revenue for the three months ended September 30, 2012 compared to the same period in 2011.

Exploration Expense: Exploration expense decreased $50,886 or 45% to $62,415 for the three months ended September 30, 2012 from $113,301 for the three months ended September 30, 2011. The change is not considered meaningful and simply reflects the timing of expenses for exploration activities.

General and Administrative Expense: General and administrative expenses increased $231,285 or 52% to $676,376 for the three months ended September 30, 2012 from $445,091 for the three months ended September 30, 2011. The G&A burn rate was higher for this this period in 2012 partially due to additional headcount in Austin, a chief financial officer and an accounting manager, and non-recurring costs associated with the transfer of accounting services from California to Texas. This increase reflects the bad debt expense of $200,000 recorded in the third quarter of 2012 associated with the sale of oil and natural gas assets to CO Energy in May 2012, warrants issued for Board service, all net of a negative adjustment for warrants authorized in a prior period of this year.

Depletion and Accretion: Depletion, accretion, and depreciation increased $5,513 or 54% to $15,679 for the three months ended September 30, 2012 from $10,166 for the three months ended September 30, 2011. The increase reflects the increase in the amount of producing wells in the during the respective time periods.

Impairment of Assets: During the three months ended September 30, 2012, the Company recorded $162,703 in asset impairment charges for our Uno Mas well which was deemed not commercial and a charge associated with the write-off of other undeveloped land costs in New Mexico. There were no impairment charges for the three months ending September 30, 2011.

Interest Expense: Interest expense was $3,040 for the three months ending September 30, 2012. This represents the 10% preferred return which Navitus receives under the Second Amended Partnership Agreement for capital contributions to Aurora arranged by Navitus. During the three months ended September 30, 2011, the Company incurred $332,604 in interest expense virtually all of which was associated with the Company’s 10% Senior Secured Convertible Debentures which were converted to common stock on February 29, 2012.

Income Taxes: There is no provision for income tax recorded for either the three months ended September 30, 2012 or for the three months ended September 30, 2011 due to the expected operating losses of both years. The original provision of an income tax benefit of $76,671 for the three months ended September 30, 2011 has been eliminated in restatement due to applying a net realizable value evaluation. We had available Federal income tax net operating loss (“NOL”) carry forwards of 12,960,120 at December 31, 2011. Our NOL generally begins to expire in 2027.

Net Loss: We had a net loss of $644,131 for the three months ended September 30, 2012 compared to a net loss of $820,048 for the three months ended September 30, 2011. The net loss for the three months ended September 30, 2012 included $200,000 in bad debt allowance recognized for the final payment due in July, 2012, on the sale of the Jones County Oil Play and the Atwood Secondary Oil Recovery recorded May 10, 2012. The net loss for the three months ended September 30, 2012 should be viewed in light of the cash flow from operations discussed below.

Nine Months Ended September 30, 2012 Compared to the Nine Months Ended September 30, 2011

Revenues: All of our revenue was derived from the sale of oil and natural gas. Our revenues decreased $44,643 or 17.6% to $209,151 for the nine months ended September 30, 2012 from $253,794 for the nine months ended September 30, 2011. The decrease reflects a decline in both the price and volume of natural gas sold for the nine months ending September 30, 2012 from the nine months ended September 30, 2011. The decline in physical gas production is attributable to the normal productivity decline that occurs with these types of wells over time.

Lease Operating Expenses: Our cost of production decreased $25,690 or 28% to $64,695 for the nine months ended September 30, 2012 from $90,385 for the nine months ended September 30, 2011. The decrease is primarily due to a credit received from a drilling services company in early 2012 for an over-charge paid in 2011.

Production Taxes: Production taxes decreased $6,313 or 28.6% to $15,780 for the nine months ended September 30, 2012 from $22,093 for the nine months ended September 30, 2011. The decrease is primarily due to the effect of lower gas volumes and sales prices in 2012 compared to 2011.

Exploration Expense: Exploration expense increased $54,037 or 30.7% to $229,611 for the nine months ended September 30, 2012 from $175,574 for the nine months ended September 30, 2011. The increase reflects the higher overall level of exploration activities for the nine months ended September 30, 2012 compared to the nine month period ended September 30, 2011.

General and Administrative Expense: General and administrative expenses increased $523,530 or 46% to $2.2 million for the nine months ended September 30, 2012 from $1.5 million for the nine months ended September 30, 2011. For the most part, the increase reflects the increase in non-recurring accounting service expenses associated with the transfer of the accounting function from Irvine, CA, to Austin, TX during the three month period ending September 30, 2012 and the compensation expense associated with the addition of one officer and one employee compared to no such costs for the same three months ending September 30, 2011. The increase reflects charges in 2012 related to a bad debt expense associated with the sale of oil and natural gas assets in May 2012, grants related to non-qualified stock options to employees and officers of the Company, the amortization of previous of stock option as they vest over time, the cost of warrants granted to affiliates and non-affiliates is of the Company for special consulting assistance in certain undertakings of the Company, and warrants granted to a related party to serve as general counsel of the Company all net of a negative adjustment for warrants authorized in a prior period of this year.

Depletion and Accretion: Depletion, accretion, and depreciation increased $6,990 or 17.1% to $47,760 for the nine months ended September 30, 2012 from $40,770 for the nine months ended September 30, 2011. The increase is due to the additional depletion of the operating oil wells in early 2012 which the Company did not have in the nine months ending September 30, 2011 notwithstanding the reduction in amount of assets subject to depletion as a result of the sale of the Jones County/Atwood properties in May, 2012.

Gain on Sale of Assets: On May 10, 2012, the Company sold its interests in the Jones County Oil Play and the Atwood Secondary Oil Recovery project for $400,000 in cash payable in two even installments in May and July, 2012. The sale resulted in a one-time gain of $268,169. The Company has recognized a bad debt allowance of $200,000 against the second installment which was due in July, 2012.

Impairment of Assets: During the nine months ended September 30, 2012, the Company recorded $162,703 in asset impairment charges for our Uno Mas well which was deemed not commercial and a charge associated with the write-off of other undeveloped land costs in New Mexico. There were no impairment charges for the nine months ending September 30, 2011.

Interest Expense: Interest expense increased $2.5 million to $4.0 million for the nine months ended September 30, 2012 from $1.5 million for the nine months ended September 30, 2011. For the nine months ended September 30, 2012, $265,460 represents the amortization of the non-cash debt discount associated with the sale of the 10% Senior Secured Convertible Debentures from January 1, 2012 up to the point where the 10% Senior Secured Convertible Debentures were converted to common stock on February 29, 2012, $3.7 million represents the recognition of the remaining non-cash debt discount associated with the conversion of all the outstanding 10% Senior Secured Convertible Debentures to common stock on February 29, 2012, and $57,100, for the most part, represents the actual interest expense accrued on the10% Senior Secured Convertible Debentures outstanding until the conversion of the 10% Senior Secured Convertible Debentures on February 29, 2012, and $3,040 represents the 10% return paid to Navitus for arranging for additional contributions to Aurora.

Income Taxes: There is no provision for income tax recorded for either the nine months ended September 30, 2012 or for the nine months ended September 30, 2011 due to the expected operating losses of both years. The original provision of an income tax benefit of $466,703 for the nine months ended September 30, 2011 has been eliminated in restatement due to applying a net realizable value evaluation. We had available NOL carry forwards of 12,960,120 at December 31, 2011. Our NOL generally begins to expire in 2027.

Net Loss: We had a net loss of $6.1 million for the nine months ended September 30, 2012 compared to a net loss of $2.6 million for the nine months ended September 30, 2011. This net loss should be viewed in light of the cash flow from operations discussed below.

Liquidity and Capital Resources

Our cash, total current assets, total assets, total current liabilities, and total liabilities as of September 30, 2012 as compared to September 30, 2011, are as follows:

	Sept. 30, 2012	Sept. 30, 2011
Cash	$ 99,363	$ 223,231
Total current assets	164,246	345,455
Total assets	1,804,004	1,397,094
Total current liabilities	229,882	330,192
Total liabilities	259,886	744,156

At September 30, 2012, we had a working capital deficit of $65,636 compared to a working capital surplus of $15,263 at September 30, 2011. Current liabilities decreased to $229,882 at September 30, 2012 from $330,192 at September 30, 2011 primarily due to the pay down of accounts payable offset somewhat by an increase in accrued royalties and the conversion of accrued interest to common stock.

Net cash used in operating activities for the nine months ended September 30, 2012 was $1.6 million after the net loss of $6.1 million was decreased by $4.7 million in non-cash charges and offset by $178,487 in changes to the working capital accounts. This compares to cash used in operating activities for the nine months ended September 30, 2011 of $1.6 million after the net loss for that period of $2.6 million was decreased by $1.2 million in non-cash charges offset by $113,398 in changes to the working capital accounts.

Net cash used in investing activities for the nine months ended September 30, 2012 was $936,292 of which $263,650 was for drilling and related costs for exploration efforts, $661,983 was used to acquire land and rights to land for drilling, and $10,359 was used to purchase furniture and fixtures for the Austin, Texas office. This compares to $417,567 in drilling costs and $8,329 in purchases of furniture and fixtures for the then new Austin, Texas office during the nine months ended September 30, 2011. $200,000 came from the sale of the Company’s investment in the Jones County/Atwood properties.

Net cash provided by financing activities for the nine months ended September 30, 2012 was $2.3 million of which $1.8 million came from the sale of the Company’s 10% Senior Secured Convertible Debentures, $349,900 came from contributions from Navitus, and $4,874 came from the exercise of warrants. In the meantime, $61,472 in distributions were made to Navitus in accordance with the Second Amended Aurora Partnership Agreement. This compares to $2.2 million provided by financing activities during the nine months ended September 30, 2011 of which $2.3 million came from the sale of the Company’s 10% Senior Secured Convertible Debentures while $68,667 was used to pay down a bank line of credit and $50,000 was used to pay off a note due a related party.

Recently Issued Accounting Pronouncements

Recent Accounting Pronouncements

During the period ended December 31, 2012, the FASB issued ASU 2013-07, "Presentation of Consolidated financial statements (Topic 205): Liquidation Basis of Accounting." The ASU requires organization to prepare its consolidated financial statements using the liquidation basis of accounting when liquidation is "imminent." Liquidation is considered imminent when the likelihood is remote that the organization will return from liquidation and either: (a) a plan for liquidation is approved by the person or persons with the authority to make such a plan effective and the likelihood is remote that the execution of the plan will be blocked by other parties; or (b) a plan for liquidation is being imposed by other forces (e.g., involuntary bankruptcy). In cases where a plan for liquidation was specified in the organization's governing documents at inception (e.g., limited-life entities), the organization should apply the liquidation basis of accounting only if the approved plan for liquidation differs from the plan for liquidation that was specified in the organization's governing documents. This ASU is effective for interim and annual reporting periods beginning after December 15, 2013, with early adoption permitted. The adoption of this standard is not expected to have an impact on the Company's (consolidated) financial position and results of operations.

During the period ended December 31, 2012, the FASB has issued Accounting Standards Update (ASU) No. 2013-04, Liabilities (Topic 405): Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation Is Fixed at the Reporting Date. ASU 2013-04 provides guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation within the scope of this ASU is fixed at the reporting date, except for obligations addressed within existing guidance in U.S. GAAP. The guidance requires an entity to measure those obligations as the sum of the amount the reporting entity agreed to pay on the basis of its arrangement among its co-obligors and any additional amount the reporting entity expects to pay on behalf of its co-obligors. The amendments in this ASU are effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. For nonpublic entities, the amendments are effective for fiscal years ending after December 15, 2014, and interim periods and annual periods thereafter. The adoption of this standard is not expected to have a material impact on the Company's (consolidated) financial position and results of operations.

In September 2011, the FASB issued Accounting Standard Update ("ASU") No. 2011-08, Intangible – Goodwill and Other (Topic 350), Testing Goodwill for Impairment. Under the amendments of this ASU, an entity has the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If, after assessing the totality of events or circumstances, an entity determines it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then performing the two-step impairment test is unnecessary. However, if an entity concludes otherwise, then it is required to perform the first step of the two-step impairment test by calculating the fair value of the reporting unit and comparing the fair value with the carrying amount of the reporting unit, as described in paragraph 350-20-35-4. If the carrying amount of a reporting unit exceeds its fair value, then the entity is required to perform the second step of the goodwill impairment test to measure the amount of the impairment loss, if any, as described in paragraph 350-20-35-9. Under the amendments in this Update, an entity has the option to bypass the qualitative assessment for any reporting unit in any period and proceed directly to performing the first step of the two-step goodwill impairment test. An entity may resume performing the qualitative assessment in any subsequent period. This ASU is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011. The adoption of this ASU did not have a material effect on the Company's consolidated financial statements.

In June 2011, the FASB issued ASU No. 2011-05, Comprehensive Income (Topic 220), and Presentation of Comprehensive Income. Under the amendments of this ASU, an entity has the option to present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In both choices, an entity is required to present each component of net income along with total net income, each component of other comprehensive income along with a total for other comprehensive income, and a total amount for comprehensive income. In a single continuous statement, the entity is required to present the components of net income and total net income, the components of other comprehensive income and a total for other comprehensive income, along with the total of comprehensive income in that statement. In the two-statement approach, an entity is required to present components of net income and total net income in the statement of net income. The statement of other comprehensive income should immediately follow the statement of net income and include the components of other comprehensive income and a total for other comprehensive income, along with a total for comprehensive income. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. The adoption of this ASU did not have a material effect on the Company's consolidated financial statements.

Summary of Critical Accounting Policies

Consolidation Policy

The Company's management, in considering accounting policies pertaining to consolidation, has reviewed the relevant authoritative guidance. The Company follows this authoritative, in assessing whether the rights of the non-controlling interests should overcome the presumption of consolidation when a majority voting, or controlling interest in its investee "is a matter of judgment that depends on facts and circumstances." In applying the circumstances and contractual provisions of the Partnership Agreement, management determines that the non-controlling rights do not, individually or in the aggregate, provide for the non-controlling interest to "effectively participate in significant decisions that would be expected to be made in the ordinary course of business." The rights of the non-controlling interest are protective in nature. The Company has corrected, pursuant to the Securities Exchange Commission directives, the audited consolidated financial statements for 2010 and 2011, as well as the unaudited quarterly statements for 2011 and 2012, to report the net income or loss and equity attributable to non-controlling interests (NCI), in accordance with ASC 810.

Use of Estimates

The preparation of consolidated financial statements in conformity with U.S. generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the periods reported. Actual results could differ from these estimates.

Significant estimates include volumes of oil and natural gas reserves used in calculating depletion of proved oil and natural gas properties, future net revenues and abandonment obligations, impairment of proved and unproved properties, future income taxes and related assets and liabilities, the fair value of various common stock, warrants and option transactions, and contingencies. Oil and natural gas reserve estimates, which are the basis for unit-of-production depletion and the calculation of impairment, have numerous inherent uncertainties. The accuracy of any reserve estimate is a function of the quality of available data, the engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. In addition, reserve estimates are vulnerable to changes in wellhead prices of crude oil and natural gas. Such prices have been volatile in the past and can be expected to be volatile in the future.

These significant estimates are based on current assumptions that may be materially affected by changes to future economic conditions such as the market prices received for sales of volumes of oil and natural gas, interest rates, the fair value of the Company’s common stock and corresponding volatility, and the Company’s ability to generate future taxable income. Future changes to these assumptions may affect these significant estimates materially in the near term.

Oil and Natural Gas Properties

We account for investments in oil and natural gas properties using the successful efforts method of accounting. Under this method of accounting, only successful exploration drilling costs that directly result in the discovery of proved reserves are capitalized. Unsuccessful exploration drilling costs that do not result in an asset with future economic benefit are expensed. All development costs are capitalized because the purpose of development activities is considered to be building a producing system of wells, and related equipment facilities, rather than searching for oil and natural gas. Items charged to expense generally include geological and geophysical costs. Capitalized costs for producing wells and associated land and other assets are depleted using a Units of Production methodology based on the proved, developed and calculated by well basis by an independent petroleum engineer in accordance with SEC rules.

The net capitalized costs of proved oil and natural gas properties are subject to an impairment test which compares the net book value of assets, based on historical cost, to the discounted future cash flow of remaining oil and natural gas reserves based on current economic and operating conditions. Impairment of an individual producing oil and natural gas field is first determined by comparing the undiscounted future net cash flows associated with the proved property to the carrying value of the underlying property. If the cost of the underlying property is in excess of the undiscounted future net cash flows the carrying cost of the impaired property is compared to the estimated fair value and the difference is recorded as an impairment loss. Management’s estimate of fair value takes into account many factors such as the present value discount rate, pricing, and when appropriate, possible and probable reserves when activities justified by economic conditions and actual or planned drilling or other development. For the year 2010, the Public Company Accounting Oversight Board investigated and found that the Company made an error in its accounting for impairment charges by improperly using discounted cash flows rather than the undiscounted future net cash flows, resulting in an impairment error of $114,778, which has been corrected and which impact is restated in these consolidated financial statements.

Under the successful efforts method of accounting, the depletion rate is the current period production as a percentage of the total proved producing reserves. The depletion rate is applied to the net book value of property costs to calculate the depletion expense. Proved reserves materially impact depletion expense. If the proved reserves decline, then the depletion rate (the rate at which we record depletion expense) increases, reducing net income.

We depreciate other property and equipment using the straight-line method based on estimated useful lives ranging from five to 10 years.

Long-lived Assets and Intangible Assets

The Company accounts for intangible assets in accordance with the provisions of the applicable Accounting Standards Code (“ASC”) standard. Intangible assets that have defined lives are subject to amortization over the useful life of the assets. Intangible assets held having no contractual factors or other factors limiting the useful life of the asset are not subject to amortization but are reviewed at least annually for impairment or when indicators suggest that impairment may be needed. Intangible assets are subject to impairment review at least annually or when there is an indication that an asset has been impaired.

For unproved property costs, management reviews these investments for impairment on a property-by-property basis if a triggering event should occur that may suggest that impairment may be required.

The Company reviews its long-lived assets and proved oil and natural gas properties for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable in accordance with the applicable ASC standard. Proved oil and natural gas assets are evaluated for impairment at least annually. If the carrying amount of the asset, including any intangible assets associated with that asset, exceeds its estimated future undiscounted net cash flows, the Company will recognize an impairment loss equal to the difference between its carrying amount and its estimated fair value. The fair value used to calculate the impairment for producing oil and natural gas field that produces from a common reservoir is first determined by comparing the undiscounted future net cash flows associated with total proved properties to the carrying value of the underlying evaluated property. If the cost of the underlying evaluated property is in excess of the undiscounted future net cash flows, the future net cash flows discounted at 10%, which the Company believes approximates fair value, to determine the amount of impairment.

Stock Based Compensation

The Company adopted the ASC standard related to stock compensation to account for its warrants and options issued to key partners, directors and officers. The fair value of common warrants granted is estimated at the date of grant using the Black-Scholes option pricing model by using the historical volatility of the Company's stock. The calculation also takes into account the common stock fair market value at the grant date, the exercise price, the expected life of the common stock option or warrant, the dividend yield and the risk-free interest rate.

The Company from time to time may issue warrants and restricted stock to acquire goods or services from third parties. Restricted stock, options or warrants issued are recorded on the basis of their fair value, which is measured as of the date issued. In accordance with the standard, the options or warrants are valued using the Black-Scholes option pricing model on the basis of the market price of the underlying equity instrument on the "valuation date," which for warrants related to contracts that have substantial disincentives to non-performance, is the date of the contract, and for all other contracts is the vesting date. Expense related to the options and warrants is recognized on a straight-line basis over the shorter of the period over which services are to be received or the vesting period.

Earnings per Share

Basic earnings per share are computed using the weighted average number of common shares outstanding. Diluted earnings per share reflect the potential dilutive effects of common stock equivalents such as options, warrants and convertible securities. Due to the Company incurring a net loss from continuing operations, basic and diluted loss per share are the same for the years ended December 31, 2012 and 2011 as all potentially dilutive common stock equivalents become anti-dilutive in nature.

Income Taxes

Under the applicable ASC standard, deferred income taxes are recognized at each year end for the future tax consequences of differences between the tax bases of assets and liabilities and their financial reporting amounts based on tax laws and statutory tax rates applicable to the periods in which the differences are expected to affect taxable income. We routinely assess the reliability of our deferred tax assets. We consider future taxable income in making such assessments. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized under accounting standards, it is reduced by a valuation allowance. However, despite our attempt to make an accurate estimate, the ultimate utilization of our deferred tax assets is highly dependent upon our actual production and the realization of taxable income in future periods. The Company has corrected and restated for the year 2010 and 2011, the previously reported tax benefit provision by applying net realizable valuation principles in accordance with FASB 109, FIN 48, and ASC 740-10.

Contingencies

Liabilities and other contingencies are recognized upon determination of an exposure, which when analyzed indicates that it is both probable that an asset has been impaired or that a liability has been incurred and that the amount of such loss is reasonably estimable.

Volatility of Oil and Natural Gas Prices

Our revenues, future rate of growth, results of operations, financial condition and ability to borrow funds or obtain additional capital, as well as the carrying value of our properties, are substantially dependent upon prevailing prices of oil and natural gas.

Off-Balance Sheet Arrangements

For the years ended December 31, 2012 and 2011, we had no off-balance sheet arrangements that were reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is deemed by our management to be material to investors.

Contractual Obligations

The following table summarizes our contractual obligations and commercial commitments as of December 31, 2012:

	2013	2014	2015	2016	2017	Total
Capital Leases	-	-	-	-	-	-
Operating Leases	$30,000	$12,000	-	-	-	$42,000
Purchase Obligations	-	-	-	-	-	-
Total	$30,000	$12,000	-	-	-	$42,000

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Risk

Our revenues, future rate of growth, results of operations, financial condition and ability to borrow funds or obtain additional capital, as well as the carrying value of our properties, are substantially dependent upon prevailing prices of oil and natural gas.

Volatility of Natural Gas Prices

As an indication of the dramatic way in which the price of natural gas can change, the following table provides the average price per million cubic feet (MCF) of gas which the Company received for the periods indicated:

Three Months Ending	Average Price per MCF	
March 31, 2011	$	6.49
June 30, 2011	$	6.51
September 30, 2011	$	4.84
December 31, 2011	$	4.68
March 31, 2012	$	4.52
June 30, 2012	$	3.51
September 30, 2012	$	2.97
December 31, 2012	$	3.03

Volatility of Oil Prices

The following table provides the average price per barrel of oil which the Company received for the periods indicated:

Three Months Ending	Average Price per Barrel	
March 31, 2012	$	92.24
June 30, 2012	$	90.90
September 30, 2012	$	81.39
December 31, 2012	$	83.98

Item 8. Consolidated financial statements and Supplementary Data

The information required by this Item 8 is incorporated by reference to the Index to Consolidated Financial Statements beginning at page F-1 of this Annual Report on Form 10-K.

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

See 8K filing on August 9, 2012, item 4.01 Changes to registrant’s certifying accountant and item 9.01 Exhibits.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission’s rules and forms and that such information is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

Pursuant to Rule 13a-15(e) under the Exchange Act, the Company carried out an evaluation, with the participation of the Company’s management, including the Company’s Chief Executive Officer (“CEO”) (the Company's principal executive officer), of the effectiveness of the Company’s disclosure controls and procedures (as defined under Rule 13a-15(e) under the Exchange Act) as of December 31, 2012. Based upon that evaluation, our management concluded that our control over financial reporting and related disclosure controls and procedures reflect a material weakness due to the size and nature of our Company.

Management’s Report on Internal Control over Financial Reporting

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

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim consolidated financial statements will not be prevented or detected on a timely basis. Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2012. Based on this assessment, management identified the following material weaknesses that have caused management to conclude that, as of December 31, 2012, our disclosure controls and procedures, and our internal control over financial reporting, were not effective at the reasonable assurance level:

1. We do not have sufficient segregation of duties within accounting functions, which is a basic internal control. Due to our size and nature, segregation of all conflicting duties may not always be possible and may not be economically feasible. However, to the extent possible, the initiation of transactions, the custody of assets and the recording of transactions should be performed by separate individuals. Management evaluated the impact of our failure to have segregation of duties on our assessment of our disclosure controls and procedures and has concluded that the control deficiency that resulted represented a material weakness.

2. To address this material weaknesses, management performed additional analyses and other procedures to ensure that the consolidated financial statements included herein fairly present, in all material respects, our financial position, results of operations and cash flows for the periods presented. Accordingly, we believe that the consolidated financial statements included in this report fairly present, in all material respects, our financial condition, results of operations and cash flows for the periods presented.

3. During February 2011, we engaged a corporate accountant as CFO (Robert Miranda of Miranda and Associates) who had significant SEC financial reporting and accounting experience. This individual prepared the accounting update for the years ending December 31, 2007, 2008, 2009, and 2010, including preparation of the delinquent quarterly Forms 10Q. This individual also assisted in the preparation of the 2011 quarterly reports for the periods ended March 31, 2011, June 30, 2011, and September 30, 2011, respectively as well as the Form 10K for that period. Mr. Miranda has served as audit committee chairman since April of 2009. The auditor during these reporting periods was Wilson Morgan.

4. During prior reporting years of 2010 and 2011, the Company, due to its small staff size lacked some of the expertise needed for proper SEC reporting, which led to the need for restatement for years 2010 and 2011. The Company has sought to address these deficiencies with the hiring of a full-time Controller with oil and gas and SEC experience effective June 1, 2013, and plans to seek additional public reporting assistance on and as needed basis.

This Annual Report does not include an attestation report of our independent registered public accounting firm regarding internal control over financial reporting. Management’s report was not subject to attestation by our registered public accounting firm pursuant to temporary rules of the Securities and Exchange Commission that permit us to provide only our management’s report in this Annual Report.

Changes in Internal Controls

Management has taken steps to remediate the material weakness over our control over financial reporting and related disclosure controls and procedures by implementing the following controls:

1. While the Company is still small, we now have a full-time employee serving as the Chief Executive Officer. Moreover, the Board of Directors continues to be proactively involved in the management of the business. Thus, risks associated with adequate segregation of duties have been addressed. Also, the skills and capabilities of the team, as well as ongoing advice and expertise provided by outside advisors gives assurance that our financial reporting is accurate and timely. We have disclosure processes in place to identify transactions and events to be reported, as applicable. Additional internal control enhancements are always taken into consideration and implemented as needed.

2. During February 2011, we engaged a corporate accountant, to serve as CFO (Robert Miranda of Miranda and Associates) who had significant SEC financial reporting and accounting experience. This individual assisted with the accounting update for the years ending December 31, 2007, 2008, 2009, and 2010, including preparation of the delinquent quarterly Forms 10Q. This individual also assisted in the preparation of the 2011 quarterly reports for the periods ended March 31, 2011, June 30, 2011, and September 30, 2011, respectively as well as this Form 10K. Mr. Miranda also was responsible for the selection of Wilson Morgan as auditor.

3. In January of 2012 the Company also hired a full-time CFO (Mr. Mark Biggers), separating that job from the Audit Committee Chair (Robert Miranda). Mr. Biggers, however, left the Company before year end 2012 and in turn leaving the Company without an experienced full-time CFO. Effective January 1, 2013, the Company installed a new accounting system designed for the oil and gas industry, which includes more stringent controls and safeguards of internal data and provide audit trails for transactional research and review.

Item 9B. Other Information

Change of Officers

On April 15, 2013, Vice President of Exploration, Stan Lindsey, is no longer with the Company.

There are no other events required to be disclosed by this Item.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The following table sets forth information regarding the names, ages (as of March 31, 2013) and positions held by each of our executive officers, followed by biographies describing the business experience of our executive officers for at least the past five years. Our executive officers serve at the discretion of the board of directors.

Name	Age	Positions Held
Kenneth Hill	49	Director, Chief Executive Officer, and President
David McCall	64	Director, General Counsel
Robert Grenley	56	Director
Ronald Zamber	53	Director
Robert J. Miranda	60	Director, Chairman

Kenneth Hill was appointed CEO in January 2012. Mr. Hill previously served as Victory's Vice President and Chief Operating Officer from January 2011 to January 2012 and has been a member of the Board of Directors since April 2011. Prior to joining the Company, Mr. Hill held titles of Interim CEO, VP of Operations and VP of Investor Relations for the U.S. subsidiary of a publicly traded oil and natural gas company on the Australian Stock Exchange, AUS TEX Exploration from December 2006 –to November 2010.

Since 2001, Hill through his private company has raised several million dollars of venture capital, personally invested in and consulted for a number of successful entrepreneurial ventures across a variety of industries, including oil and natural gas. Prior to 2001, Hill was employed for 16 years at Dell, Inc. As one of the first 20 employees at Dell he served in variety of management positions including manufacturing, sales, marketing, and business development. Prior to joining Dell, Hill studied Business Management and Business Marketing at Southwest Texas State University (now Texas State University). While at Dell, Mr. Hill continued his education at The University of Texas Graduate School of Business Executive Education program, The Aspen Institute and the Center for Creative Leadership. He is a team builder with a unique set of proven leadership, management and technical skills.

David McCall was appointed General Counsel and Director on January 20, 2011. Mr. McCall has over 35 years of experience in the oil and natural gas industry and has been with the law firm The McCall Firm in Austin, Texas for over five years. Mr. McCall's law practice has centered on the activities of major and independent oil companies. Mr. McCall received a Bachelor of Arts in marketing from McMurry University, Abilene, Texas in 1971. He graduated from Texas Tech School of Law, Lubbock, Texas in 1974. He is a member of the Bar, State of Texas; a Life Fellow, Texas Bar Foundation; and a Founding Fellow, Austin Bar Foundation.

Robert Grenley was appointed Director on June 1, 2010. Since May, 2007, Mr. Grenley is Chief Financial Officer of Ambient, Inc. a subsidiary of IDM Technologies, LLC, and a private company based in Gig Harbor, Washington. From 1996 through April, 2007, Mr. Grenley was President of ID Micro, a private company located in Tacoma, Washington. Mr. Grenley has over 25 years' experience in financial management, business development and entrepreneurial experience, including nine years in Radio Frequency Identification (RFID) corporate development and investor relations. Mr. Grenley holds a BA in Economics from Duke University.

Ronald W. Zamber, M.D. Director was appointed Director on January 24, 2009. Dr. Zamber brings more than 15 years of experience in corporate management and business development extending across public and private companies and non-profit organizations. Since 2000, Dr. Zamber has been president and CEO of The Eye Clinic of Fairbanks (ECF), a private, full service eye care practice based in Fairbanks, Alaska and serving the entire Alaska interior. Dr. Zamber received his bachelor's degree with high honors from the University of Notre Dame and his medical degree with honors from the University of Washington.

Robert J. Miranda, CPA was appointed as our Chief Financial Officer (CFO) on November 16, 2008. On April 28, 2009, he was appointed Chairman and interim President and CEO upon the resignation of our former President and CEO, Jon Fullenkamp. On March 28, 2011, he was appointed President and CEO. On January 10, 2012, Mr. Miranda stepped down as CFO with the appointment of Mark Biggers to that position. On January 17, 2012, Mr. Miranda stepped down as President and CEO of the company and remains Chairman of the Board and a Director, at which time Kenneth Hill was appointed as CEO. Since October 2007, Mr. Miranda has been managing director of Miranda & Associates, a professional accountancy corporation. From March 2003 through October 2007, Mr. Miranda was a Global Operations Director at Jefferson Wells, where he specialized in providing Sarbanes-Oxley compliance reviews for public companies. Mr. Miranda was a national director at Deloitte & Touche where he participated in numerous audits, corporate finance transactions, mergers, and acquisitions. Mr. Miranda is a licensed Certified Public Accountant and has over 35 years of experience in accounting, including experience in Sarbanes-Oxley compliance, auditing, business consulting, strategic planning and advisory services. Mr. Miranda holds a B.S. degree in Business Administration from the University of Southern California, a certificate from the Owner/President Management Program from the Harvard Business School and membership in the American Institute of Certified Public Accountants.

Involvement in Certain Legal Proceedings

The foregoing directors or executive officers have not been involved during the last five years in any of the following events:

Bankruptcy petitions 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;

Conviction in a criminal proceeding or being subject to a pending criminal proceeding (excluding traffic violations and other minor offenses);

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

Being found by a court of competition jurisdiction (in a civil action), the Securities and Exchange Commission or the Commodities Futures Trading Commission to have violated a federal or state securities or commodities law, and the judgment has not been reversed, suspended or vacated.

Corporate Governance and Board Composition

Our business and affairs are organized under the direction of our board of directors, which currently consists of five (5) members. The primary responsibilities of our board of directors are to provide oversight, strategic guidance, counseling and direction to our management. Our board of directors meets on a regular basis and additionally as required. Written board materials are distributed in advance as a general rule, and our board of directors schedules meetings with and presentations from members of our senior management on a regular basis and as required.

Our board of directors set schedules to meet throughout the year and also can hold special meetings and act by written consent under certain circumstances. Our board of directors met 3 times during the year ended December 31, 2012.

Limitation of Liability and Indemnification

We intend to enter into indemnification agreements with each of our directors and executive officers and certain other key employees. The form of agreement provides that we will indemnify each of our directors, executive officers, and such other key employees against any and all expenses incurred by that director, executive officer or key employee because of his or her status as one of our directors, executive officers or key employees, to the fullest extent permitted by law and our bylaws (except in a proceeding initiated by such person without board approval). In addition, the form agreement provides that, to the fullest extent permitted by law, we will advance all expenses incurred by our directors, executive officers, and such key employees in connection with a legal proceeding.

The Nevada Revised Statutes and our bylaws contain provisions relating to the limitation of liability and indemnification of directors and officers.

Our bylaws provide that we will indemnify our directors and officers to the fullest extent permitted by law, as it now exists or may in the future be amended, against all expenses and liabilities reasonably incurred in connection with their service for or on our behalf. Our bylaws provide that we shall advance the expenses incurred by a director or officer in advance of the final disposition of an action or proceeding. Our bylaws also authorize us to indemnify any of our employees or agents and permit us to secure insurance on behalf of any officer, director, employee or agent for any liability arising out of their action in that capacity, whether or not the law would otherwise permit indemnification.

The Company maintains Directors and Officers insurance on behalf of if officers and 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. Kenneth Hill, Chief Executive 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.

Compliance with Section 16(a) of the Exchange Act:

Under the securities laws of the United States, the Company's directors, its executive officers and any persons holding more than 10% of our common stock are required to report their ownership of our common stock and any changes in that ownership to the Securities and Exchange Commission. Specific due dates for these reports have been established by rules adopted by the SEC and we are required to report in this Annual Report any failure to file by those deadlines.

Based solely upon a review of Forms 3, 4, and 5, and amendments to these forms furnished to us, except as provided below, all parties subject to the reporting requirements of Section 16(a) of the Exchange Act filed on a timely basis all such required reports during and with respect to our 2012 fiscal year.

To the best of our knowledge, the number of late reports for Kenneth Hill was 1.

To the best of our knowledge, the number of late reports for David McCall was 1.

To the best of our knowledge, the number of late reports for Robert Grenley was 1.

To the best of our knowledge, the number of late reports for Ron Zamber was 1.

To the best of our knowledge, the number of late reports for Robert Miranda was 1.

Code of Ethics

We have prepared and adopted a code of ethics to apply to our principal executive officer, principal financial officer, principal accounting officer and controller, or persons performing similar functions during the year ended December 31, 2012.

Item 11. Executive Compensation

The following table sets forth the total compensation awarded to, earned by, or paid to our principal executive officers, and our other named executive officers for all services rendered in all capacities to us in 2012 and 2011.

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($)	Warrant/ Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Nonqualified Deferred Compensation ($)	All Other Compensation ($)	Total ($)
Kenneth Hill									
President and CEO	2012	180,000	-	-	55,260	-	-	-	235,260
VP and COO	2011	180,000	-	-	86,100	-	-	-	266,100
Mark Biggers (1) Chief Financial Officer	2012	220,000	-	-	96,922	-	-	-	316,922
	2011	-	-	-	-	-	-	-	-
Stanley Lindsey (2)									

VP of Exploration and Development	2012	180,000	-	-	59,512	-	-	-	239,512
VP of Exploration and Development	2011	180,000	-	-	54,000	-	-	-	234,000
Robert J. Miranda Board Chairman	2012	-	-	-	17,685	-	-	-	17,685
Board Chairman, President, and CEO	2011	180,000	-	-	36,900	-	-	-	216,900

(1) Mark Biggers voluntarily resigned from the Company, for personal reasons, in November 2012.

(2) Subsequent to December 31, 2012, Stan Lindsey is no longer employed with the Company.

Director Compensation

The following table sets forth the total compensation awarded to, earned by, or paid to each person who served as a director during the years ended December 31, 2012 and 2011, other than a director who also served as a named executive officer. Our directors who are not executive officers did not receive any cash compensation for serving on our board of directors. We have a policy of reimbursing our directors for their reasonable out-of-pocket expenses incurred in attending Board and committee meetings. Each director is paid for his or her director services in the form of 6,000 warrants granted monthly for each month of service. These five (5) year warrants are exercisable into common stock at an exercise price $0.01, and vest immediately upon issuance.

Name	Year	Fees Earned or piad in Cash ($)	Stock Awards ($)	Warrant/Option Awards ($)	Non-Equity Incentive Compensation ($)	Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)	Total ($)
Ronald Zamber	2012	-	-	230,781	-	-	-	230,781
	2011	-	-	36,900	-	-	-	36,900
Robert Grenley (1)	2012	-	-	14,760	-	-	-	14,760
	2011	-	-	36,900	-	-	-	36,900
David McCall (2)	2012	-	-	112,702	-	-	-	112,702
	2011	-	-	162,200	-	-	-	162,200

(1) Robert Grenley was appointed on June 1, 2010.

(2) David McCall was appointed on January 20, 2011.

Outstanding Equity Awards at Fiscal Year-End

The following table sets forth certain information concerning outstanding stock awards held by the named executive officers as of December 31, 2012 and 2011 which reflect a 50:1 reverse stock split in January 2012.

		Option Awards					Stock Awards			
Name	Year	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 (#)	Warrant/ Option Exercise Price ($)	Warrant/ Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other

									Have Not Vested (#)	Rights That Have Not Vested ($)
Robert J. Miranda										
Chairman	2011	24,000	-		$ 0.01	12/31/ 2016	-	-	-	-
	2010	24,000	-	-	$ 0.01	12/31/ 2015	-	-	-	-
	2009	24,000	-	-	$ 0.01	12/31/ 2014	-	-	-	-
Kenneth Hill,										
President and	2011	30,000	-	-	$ .50	12/31/ 2016	-	-	-	-
Chief Executive Officer	2011	60,000	-	50,000	$ 1.00	12/31/ 2016	-	-	-	-
Stanley Lindley										
Vice President, Exploration	2011	30,000	-	-	$ .50	12/31/ 2016	-	-	-	-
and Development	2011	60,000	-	-	$ 1.00	12/31/ 2016	-	-	-	-

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

We have no outstanding equity compensation plans under which our securities are authorized for issuance.

Security Ownership of Certain Beneficial Owners

Beneficial ownership is determined in accordance with the rules of the SEC, and generally includes voting power and/or investment power with respect to the securities held. Shares of common stock subject to options or warrants currently exercisable or exercisable within 60 days of December 31, 2012 and 2011, are deemed outstanding and beneficially owned by the person holding such options or warrants for purposes of computing the number of shares and percentage beneficially owned by such person, but are not deemed outstanding for purposes of computing the percentage beneficially owned by any other person. Except as indicated in the footnotes to these tables, and subject to applicable community property laws, the persons or entities named have sole voting and investment power with respect to all shares of our common stock shown as beneficially owned by them.

The following table sets forth, as of December 31, 2012, certain information with respect to the Company's equity securities owned or record or beneficially by (i) each officer and director of the Company; (ii) each person who owns beneficially more than 5% of each class of the Company's outstanding equity securities; and (iii) all directors and executive officer as a group:

Name and Position	Business Address	Common Stock	Vested Options	Warrants (1)	Total	Percent of Class (2)	
Kenneth Hill, President and Chief Executive Officer (3)	3355 Bee Caves Rd Ste 608 Austin, TX 78746	171,652	40,000	24,000	235,652	0.80	%
Stanley Lindsey, Vice President	3355 Bee Caves Rd Ste 608 Austin, TX 78746	145,885	40,000	-	185,885	0.60	%
David McCall, General Counsel, Director (4)	2600 Via Fortuna, Suite 200, Austin TX 78746	145,233	-	194,450	339,683	1.10	%
Robert Grenley, Director	40 Loch Lane SW, Lakewood, WA 98499	43,934	-	38,000	81,934	0.30	%
Ronald Zamber,	1919 Lathrop Suite						

Director (5)	103, Fairbanks, AK 99701	5,633,531	-	299,496	5,933,027	19.50	%
Robert Miranda, Board Chairman (6)	20341 Irvine Avenue #D6, Newport Beach, CA 92660	186,711	-	52,500	239,211	0.80	%
All Officers and Directors As a Group (6 Persons)		6,326,946	80,000	608,446	7,015,392	23.10	%

(1)All warrants are exercisable immediately

(2) Based on 30,407,905 total shares outstanding which consists of 27,563,619 shares of common stock outstanding, 220,000 of vested options, and 2,624,286 of unexercised warrants.

(3)Includes 165,830 shares owned by Already Done That LLC of which Kenneth Hill is the controlling partner and owner.

(4)Includes 145,233 shares owned by 1519 Partners LLC; David McCall is the controlling partner and of 1519 Partners LLC.

(5)Includes 2,468,138 shares owned by Visionary Investments, LLC of which Ronald Zamber is sole member; 2,437,481 shares owned by Visionary Private Equity Group I, LP of which Ronald Zamber is chairman, and managing director.

(6)Includes 184,711 shares owned by the Miranda & Associates 401k plan. Robert Miranda is the trustee of the Miranda & Associates 401k plan.

There are no classes of stock other than common stock issued or outstanding.

The Company is not aware of any current arrangements which will result in a change in control.

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

Related Party Transactions

During the year ended December 31, 2012, we incurred a total of $153,355 of accounting services with Miranda & Associates, a Professional Accountancy Corporation ("Miranda"). As of December 31, 2012, Miranda was owed $825 for these professional services. One of our directors, Robert J. Miranda, is the managing director of Miranda.

During the year ended December 31, 2012 we incurred a total of $198,009 in legal fees with The McCall Firm. David McCall, our general counsel and a director, is a partner in The McCall Firm. The fees are attributable to litigation involving the Company's oil and natural gas operations in Texas. As of December 31, 2012, the Company owed The McCall Firm approximately $16,679 for these professional services.

Director Independence

Our Board has determined that each of our directors qualifies as an independent director under applicable rules promulgated by the SEC and the NASDAQ Stock Market listing standards, although our common stock is not listed on NASDAQ, and has concluded that none of these directors has a material relationship with the Company that would interfere with the exercise of independent judgment in carrying out the responsibilities of a director.

Item 14. Principal Accounting Fees and Services

Audit Fees

We did not file when due our Annual Report on Form 10-K for the fiscal years ended December 31, 2007, (restated), 2008, 2009, and 2010, or Quarterly Reports on Forms 10-Q for the respective interim 2008 (restated), 2009 and 2010 periods until March and May, 2011, respectively. Accordingly, the aggregate fees billed for the fiscal year ended December 31, 2011 for professional services rendered by the principal accountant for the audit of our annual consolidated financial statements and review of the consolidated financial statements or services that are normally provided by the accountant in connection with statutory and regulatory filings or engagements for that fiscal year were higher than would otherwise be expected for a normal year. For the years ended December 31, 2012 and 2011 respectively, we paid $88,257 and $135,465, respectively, in fees to our principal accountants.

Tax Fees

For the fiscal years ended December 31, 2012 and 2011, our principal accountants did not render any services for tax compliance, tax advice, and tax planning work.

All Other Fees

None.

All fees described above for the years ended December 31, 2012 and 2011, were approved by the entire board of directors.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) (1) and (2) Consolidated financial statements and Schedules

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS (a)(3) Exhibits

Refer to (b) below.

(b) Exhibits

3.1	Articles of Incorporation of All Things, Inc., filed on January 7, 1982 incorporated by reference to Exhibit 3.1 of the Company's Annual Report on Form 10-K filed with the SEC on March 29, 2011.
3.2	Certificate of Amendment of Articles of Incorporation, filed on January 7, 1982 incorporated by reference to Exhibit 3.2 of the Company's Annual Report on Form 10-K filed with the SEC on March 29, 2011.
3.3	Certificate of Amendment of Articles of Incorporation, filed on March 21, 1985 incorporated by reference to Exhibit 3.3 of the Company's Annual Report on Form 10-K filed with the SEC on March 29, 2011.
3.4	Certificate of Amendment of Articles of Incorporation, filed on November 1, 1995 incorporated by reference to Exhibit 3.4 of the Company's Annual Report on Form 10-K filed with the SEC on March 29, 2011.
3.5	Certificate of Amendment of Articles of Incorporation, filed on April 28, 2003 incorporated by reference to Exhibit 3.5 of the Company's Annual Report on Form 10-K filed with the SEC on March 29, 2011.
3.6	Certificate of Amendment of Articles of Incorporation, filed on May 3, 2006 incorporated by reference to Exhibit 3.6 of the Company's Annual Report on Form 10-K filed with the SEC on March 29, 2011.
3.7	Certificate of Amendment of Articles of Incorporation, filed on May 10, 2006 incorporated by reference to Exhibit 3.7 of the Company's Annual Report on Form 10-K filed with the SEC on March 29, 2011.
3.8	Certificate of Amendment of Articles of Incorporation, filed on August 22, 2006 incorporated by reference to Exhibit 3.8 of the Company's Annual Report on Form 10-K filed with the SEC on March 29, 2011.
3.9	Certificate of Amendment of Articles of Incorporation, filed on October 3, 2008 incorporated by reference to Exhibit 3.9 of the Company's Annual Report on Form 10-K filed with the SEC on March 29, 2011.
3.10	Certificate of Amendment of Articles of Incorporation, filed on November 18, 2011 as part of Form 14C. Attached to this Form 10K as Exhibit 3.10
3.11	Bylaws of Victory Energy Corporation incorporated by reference to Exhibit 3.10 of the Company's Annual Report on Form 10-K filed with the SEC on March 29, 2011.
10.1	Unsecured Promissory Notes (Zamber) incorporated by reference to Exhibit 10.1 of the Company's Annual Report on Form 10-K filed with the SEC on March 29, 2011.

10.2	Separation Agreement by and between Victory Energy Corporation and Jon Fullenkamp dated May 15, 2009 incorporated by reference to Exhibit 10.3 of the Company's Annual Report on Form 10-K filed with the SEC on March 29, 2011.
10.3	The Victory Energy Corporation/James Capital Energy, LLC, Joint Venture Partnership Agreement by and between Victory Energy Corporation, James Capital Energy, LLC and James Capital Consulting dated December 31, 2009 incorporated by reference to Exhibit 10.2 of the Company's Annual Report on Form 10-K filed with the SEC on March 29, 2011.
10.4	Settlement Agreement and Mutual General Release by and between Jon Fullenkamp and Xploration, on the one hand; and Victory Energy Corporation, James Capital Energy, LLC, James Capital Consulting, LLC, James Capital, LLC, Aurora Energy Partners, Zamber Energy Investments, LLC, International Vision Quest, Miranda & Associates, Ronald Zamber, Robert Miranda, Richard May, and Tom Konz, on the other hand, incorporated by reference to Exhibit 10.5 of the Company's Annual Report on Form 10-K filed with the SEC on March 29, 2011.
10.5	Consulting Services Agreement by and between Victory Energy Corporation and Miranda & Associates, A Professional Accountancy Corporation dated November 16, 2008 incorporated by reference to Exhibit 10.6 of the Company's Annual Report on Form 10-K filed with the SEC on March 29, 2011.
10.6	Consulting Services Agreement by and between the Victory Energy Corporation and Miranda & Associates, A Professional Accountancy Corporation, dated August 1, 2009 incorporated by reference to Exhibit 10.7 of the Company's Annual Report on Form 10-K filed with the SEC on March 29, 2011.
10.7	First Amendment to The Victory Energy Corporation/James Capital Energy, LLC, Joint Venture Partnership Agreement, changing the name of the Partnership to "Aurora Energy Partners, A Texas General Partnership", dated March 31, 2011
10.8	Option Agreement by and among Victory Energy Corporation, Santiago Resources, LP, 1519 Partners, LP, Via Fortuna Minerals, LLC, Wesley G. Ritchie, and Barrier Island Minerals, LLC dated December 20, 2010 incorporated by reference to Exhibit 99.1 of the Company's Form 8-K filed with the SEC on January 4, 2011.
10.9	Second Amendment to The Victory Energy Corporation/James Capital Energy, LLC, Joint Venture Partnership Agreement, In which the Company agreed with The Navitus Energy Group ("Navitus"), James Capital Consulting, LLC ("JCC"), and James Capital Energy, LLC ("JCE") to amend certain terms of the Aurora Energy Partners partnership ("Aurora") and to substitute Navitus, a Texas general partnership composed of JCC, JCE, Rodinia Partners, LLC, and Navitus Partners, LLC, as partner for JCC and JCE in Aurora. The effective date of the Second Amended Partnership Agreement is October 1, 2011. In addition, the Second Amendment effectively increases the Company's interest in the profits and losses of Aurora from 15% to 50%. The Second Amendment is incorporated by reference to Exhibit 99.1 of the Company's Form 8-K filed with the SEC on December 9, 2011.
10.1	Oil and natural gas Reserves Report prepared by J.A. Nicholson dated February 22, 2013
31.1	Rule 13a-14(a)/15d-14(a) Certification of Kenneth Hill
31.2	Rule 13a-14(a)/15d-14(a) Certification of Kenneth Hill
32	Section 1350 Certification of Kenneth Hill

SIGNATURES

In accordance with Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this Annual Report to be signed on its behalf by the undersigned, thereunto duly authorized.

VICTORY ENERGY CORPORATION

Date: November 12, 2013	By:	/s/ Kenneth Hill Kenneth Hill Chief Executive Officer and Director

Pursuant to Form 10-K General Instruction D.2(a), missing the following required signatures: 1.) principal financial officer and 2.) controller or principal accounting officer. In accordance with the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date: November 12, 2013	By:	/s/ Ronald W. Zamber Ronald W. Zamber Director
Date: November 12, 2013	By:	/s/ Patrick Barry Patrick Barry Audit Committee Chairman and Director
Date: November 12, 2013	By:	/s/ Robert Grenley Robert Grenley Director
Date: November 12, 2013	By:	/s/ David B. McCall David B. McCall General Counsel and Director

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Victory Energy Corporation
Austin, Texas

We have audited the accompanying consolidated balance sheets of Victory Energy Corporation (the "Company") as of December 31, 2012 and December 31, 2011 (restated), and the related consolidated statements of operations, stockholders' equity and cash flows for 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 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 consolidated 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 includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated 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 consolidated financial position of the Company as of December 31, 2012 and December 31, 2011 (restated), and the consolidated results of its operations and its cash flows for the years ended December 31, 2012 and December 31, 2011 (restated), in conformity with accounting principles generally accepted in the United States of America.

The accompanying consolidated financial statements have been prepared assuming the Company will continue as a going concern. The Company has experienced recurring losses since its inception and has an accumulated deficit. These conditions raise substantial doubt regarding the Company's ability to continue as a going concern. Management's plans in regard to these matters are described in Note 1 to the consolidated financial statements. The consolidated financial statements do not include any adjustments to reflect the possible future effects on the recoverability and classification of assets or the amounts and classification of liabilities that may result from the outcome of this uncertainty.

/s/ Marcum, LLP

Los Angeles, California

November 12, 2013

VICTORY ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

December 31, 2012 and 2011

ASSETS	12/31/2012	(Restated) 12/31/2011
Current Assets		
Cash and cash equivalents	$158,165	$475,623
Accounts receivable - less allowance for doubtful accounts of $200,000, and $0 for 2012 and 2011, respectively	157,481	79,185
Prepaid expenses	68,693	29,555
Total current assets	384,339	584,363
Fixed Assets		
Furniture and equipment	43,173	10,623
Accumulated depreciation	(5,521)	(3,550)
Total furniture and fixtures, net	37,652	7,073
Producing oil and natural gas properties, net of impairment	2,583,504	2,134,570
Accumulation depletion	(1,145,514)	(1,099,211)
Total oil and gas properties, net	1,437,990	1,035,359
Total Assets	$1,859,981	$1,626,795
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$4,339	$326,973
Accrued interest	25,639	150,267
Accrued liabilities	216,444	179,979
Accrued liabilities - related parties	17,504	-
Liability for unauthorized preferred stock issued	9,283	32,164
Total current liabilities	273,209	689,383
Other Liabilities		
Senior secured convertible debenture, net of debt discount	-	632,534
Asset retirement obligations	39,905	30,004
Total long term liabilities	39,905	662,538
Total liabilities	313,114	1,351,921
Stockholders' Equity		
Common stock, $0.001 par value, 47,500,000 shares authorized, 27,563,619 shares and 7,647,494 shares issued and outstanding for 2012 and 2011, respectively	402,220	382,308
Additional paid-in capital	33,950,417	26,627,222
Accumulated deficit	(35,215,267)	(28,475,589)
Total Victory Energy Corporation stockholders' deficit	(862,630)	(1,466,059)
Non-controlling interest	2,409,497	1,740,933

Total stockholders' equity	1,546,867	274,874
Total Liabilities and Stockholders' Equity	$1,859,981	$1,626,795

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

VICTORY ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
For the years ended December 31, 2012 and 2011

	12/31/2012	(Restated) 12/31/2011
Revenues		
Oil and gas sales	$326,384	$305,180
Total revenues	326,384	305,180
Operating Expenses:		
Lease operating costs	126,131	121,580
Dry hole costs	54,678	-
Production taxes	24,649	39,156
Exploration	266,514	559,523
General and administrative	2,823,939	2,094,768
Impairment of oil and natural gas properties	344,353	102,579
Depreciation/depletion/accretion	51,172	82,673
Total operating expenses	3,691,436	3,000,279
Loss from operations	(3,365,052)	(2,695,099)
Other Income (Expense):		
Gain on sale of oil and gas assets	275,489	-
Gain on settlement with former officer	-	404,624
Interest expense	(4,009,979)	(1,815,038)
Total other income and expense	(3,734,490)	(1,410,414)
Loss before Tax Benefit	(7,099,542)	(4,105,513)
Tax benefit	-	-
Net loss	(7,099,542)	(4,105,513)
Less: Net loss attributable to non-controlling interest	(359,864)	(399,511)
Net loss attributable to Victory Energy Corporation	$(6,739,678)	$(3,706,002)
Weighted average shares, basic and diluted	23,292,609	5,281,307
Net loss per share, basic and diluted	$(0.29)	$(0.70)

The accompanying notes are an integral part of the consolidated financial statements

VICTORY ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOW

For the years ended December 31, 2012 and 2011

	12/31/2012	(Restated) 12/31/2011
CAS H FLOWS FROM OPERATING ACTIVITIES		
Net loss	$(7,099,542)	$(4,105,513)
Adjustments to reconcile net loss to net cash used in operating activities provided by operating activities		
Accretion of asset retirement obligation	2,899	1,453
Amortization of debt discount and financing warrants	348,198	714,788
Unamortized discount on debentures converted to common stock	3,661,781	902,908
Depletion and depreciation	48,273	81,220
Gain from sale of oil and gas assets	(275,489)	-
Bad debt expense	200,000	-
Expiration of exploration option	-	25,000
Gain on settlement with former officer	-	(404,624)
Impairment of oil and natural gas properties	344,353	102,579
Stock based compensation	191,719	108,000
Stock grants in exchange for services	17,500	-
Warrants for services	496,979	312,000
Change in working capital		
Accounts receivable	(278,296)	(4,357)
Prepaid expense	(39,138)	8,349
Accounts payable	(322,634)	98,619
Accounts payable - related parties	17,504	(113,931)
Accrued liabilities	36,465	284,866
Net cash used in operating activities	(2,649,428)	(1,988,643)
CAS H FLOWS FROM INVES TING ACTIVITIES :		
Purchase of oil wells	-	(219,700)
Drilling costs	(8,925)	(369,695)
Acquisition of oil and gas properties	(675,058)	-
Proceeds from sale of oil and gas properties	200,000	-
Purchase of furniture and fixtures	(32,550)	(8,329)
Net cash used in investing activities	(516,533)	(597,724)
CAS H FLOWS FROM FINANCING ACTIVITIES :		
Proceeds from issuance of senior secured convertible debentures	1,815,000	3,120,000
Non-controlling interest contributions	1,089,900	-
Non-controlling interest distributions	(61,472)	(50,915)
Exercise of warrants for cash	5,075	-
Bank line of credit - net of repayments	-	(68,667)
Payments on notes payable to related party	-	(50,000)
Net cash provided by financing activities	2,848,503	2,950,418
Net Change in Cash and Cash Equivalents	(317,458)	364,051
Beginning Cash and Cash Equivalents	475,623	111,572

Ending Cash and Cash Equivalents	$158,165	$475,623
Supplemental cash flow information - cash paid for :		
Interest	$-	$47,665
Income taxes	$-	$-
Non-cash investing and financing activities:		
Preferred stock converted to common stock	$167,059	$53,490
Debentures exchanged for common stock	$4,649,775	$1,112,500

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

VICTORY ENERGY CORPORATION AND SUBSIDARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

	Common Stock $0.001 Par Value Number	Amount	Additional Paid In Capital	Accumulated Deficit	Non-controlling Interest	Total Equity (Deficit)
Balance, December 31, 2010 (Restated) - Note 1	2,740,734	$ 136,720	$ 22,128,880	$ (24,769,587)	$ 2,191,359	$ (312,628)
Distributions to noncontrolling interest owners	-	-	-	-	(50,915)	(50,915)
Beneficial conversion feature on convertible debentures	-	-	3,042,317			3,042,317
Fair value of warrant attached to convertible debentures	-	-	77,683	-	-	77,683
Unauthorized preferred stock converted to common stock	310,000	15,500	37,990	-	-	53,490
Debentures converted to common stock	4,445,000	222,500	890,000			1,112,500
Accrued interest on debentures exchanged for common stock	151,760	7,588	30,352			37,940
Stock based compensation	-	-	108,000	-	-	108,000
Warrants in exchange for services	-	-	312,000	-	-	312,000
Net loss	-	-	-	(3,706,002)	(399,511)	(4,105,513)
Balance, December 31, 2011 (Restated) - Note 1	7,647,494	$ 382,308	$ 26,627,222	$ (28,475,589)	$ 1,740,933	$ 274,874
Distributions to noncontrolling interest owners	-	-	-	-	(61,472)	(61,472)
Contributions from noncontrolling interest owners	-	-	-	-	1,089,900	1,089,900

Unauthorized preferred stock converted to common stock	340,000	357	166,702	-	-	167,059
Debentures converted to common stock	19,505,523	19,505	4,630,270	-	-	4,649,775
Stock based compensation	-	-	191,719	-	-	191,719
Beneficial conversion feature on convertible debentures	-	-	1,753,359	-	-	1,753,359
Fair value of warrant attached to convertible debentures	-	-	61,641	-	-	61,641
Warrants in exchange for services	-	-	496,979	-	-	496,979
Stock grants in exchange for services	50,000	50	17,450	-	-	17,500
Exercise of warrants for cash	20,602	-	5,075			5,075
Net loss	-	-	-	(6,739,678)	(359,864)	(7,099,542)
Balance December 31, 2012	27,563,619	$ 402,220	$ 33,950,417	$ (35,215,267)	$ 2,409,497	$ 1,546,867

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

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Victory Energy Corporation and Subsidiaries
Notes to the Consolidated Financial Statements

Note 1 – Organization and Summary of Significant Accounting Policies:

Victory Energy Corporation (Victory) is an independent, growth oriented oil and natural gas company engaged in the acquisition, exploration and production of oil and natural gas properties, through its partnership with Aurora Energy Partners. The Company is engaged in the exploration, acquisition, development, and production of domestic oil and natural gas properties. Current operations are primarily located onshore in Texas and New Mexico. The Company was organized under the laws of the State of Nevada on January 7, 1982. The Company is authorized to issue 47,500,000 shares of $0.001 par value common stock, and has 27,563,619 shares of common stock outstanding as of December 31, 2012. On January 12, 2012 the Company implemented a 50:1 reverse stock split. All information is this form 10K reflects the recent stock split. Our corporate headquarters are located at 3355 Bee Caves Rd. Ste. 608, Austin, TX 78746.

A summary of significant accounting policies followed in the preparation of the accompanying consolidated financial statements is set forth below.

Basis of Presentation and Consolidation, Including Restatement:

Victory is the managing partner of Aurora Energy Partners, a Texas General Partnership (“Aurora”), and holds a 50% partnership interest in Aurora. Aurora is consolidated with Victory for financial statement purposes, as the terms of the partnership agreement gives Victory effective control of the partnership. The consolidated financial statements include the accounts of Victory and the accounts of Aurora. The Company’s management, in considering accounting policies pertaining to consolidation, has reviewed the relevant accounting literature. The Company follows that literature, in assessing whether the rights of the non-controlling interests should overcome the presumption of consolidation when a majority voting, or controlling interest in its investee “is a matter of judgment that depends on facts and circumstances.” In applying the circumstances and contractual provisions of the partnership agreement, management determined that the non-controlling rights do not, individually or in the aggregate, provide for the non-controlling interest to “effectively participate in significant decisions that would be expected to be made in the ordinary course of business.” The rights of the non-controlling interest are protective in nature. All intercompany balances have been eliminated in consolidation. The 2011 and 2010 consolidated financial statements have been restated to present the non-controlling interest (NCI) in Aurora owned by others in the consolidated financial statements.

Non-controlling Interests:

The Navitus Energy Group is a partner with Victory in Aurora. The two partners each own a 50% interest in Aurora. Victory is the Managing Partner and has contractual authority to manage the business affairs of Aurora. The Navitus Energy Group currently has four partners. They are James Capital Consulting, LLC ("JCC"), James Capital Energy, LLC ("JCE"), Rodinia Partners, LLC and Navitus Partners, LLC. Although this partnership has been in place since January 2008, its members and other elements have changed since that time.

The non-controlling interest in Aurora is held by Navitus Energy Group, a Texas general partnership. As of December 31, 2012, $2,409,497 was recorded as the equity of the non-controlling interest in our consolidated balance sheet representing the third-party investment in Aurora, with losses attributable to non-controlling interests of $359,864 for the year ended December 31, 2012. As of December 31, 2011, $1,740,933 was recorded as the equity of the non-controlling interest in our consolidated balance sheet representing the third-party investment in Aurora, with losses attributable to the non-controlling interests of $399,511 for the year ended December 31, 2011.

Restatements and Reclassifications:

Certain prior year and quarterly amounts have been restated; to correctly present the non-controlling interest representing the third-party investment in Aurora in our consolidated financial statements; certain prior year amounts have been reclassified to conform to current year to correct an oil and gas impairment loss error; to correct the reporting of a separation agreement with a former CEO (John Fullenkamp) in March 2011; and to correct the income tax provisions for the years ended December 31, 2011 and 2010 in accordance with ASC 740, Accounting for Income Taxes.

Certain prior year amounts have been reclassified to conform to the current year presentation, which did not materially impact the restated financial statements.

Background and Restatement Adjustments

In August of 2012, the staff of the United States Securities and Exchange Commission (SEC) made inquiry to the Company regarding consolidated financial statements disclosure concerning the presentation of non-controlling interest (related to Aurora Energy Partners) on its consolidated financial statements.

Although this consolidated presentation was disclosed in the footnotes to the consolidated financial statements, as was the 50% non-controlling interest of Navitus in Aurora, the amount of non-controlling interest of Navitus in Aurora was not presented on the face of the consolidated financial statements.

After discussions with the SEC the Company determined that the amount of non-controlling interest of Navitus should also be separately stated on the face of the Company’s consolidated financial statements, in addition to being discussed in footnote disclosure. Total consolidated assets, liabilities, and stockholders equity did not change; however the non-controlling interest in Aurora is separately identified in the stockholders equity section of the consolidated financial statements. The Company net loss per share improved by the effect of the non-controlling interest in the loss of Aurora.

Resulting Restatement Adjustments:

As a result of the issues identified in the Audit Committee Review and the confirmation letter from the SEC, the consolidated financial statements were restated to present the shares of equity and shares of income and loss attributable to the Non-Controlling Interests (“NCI”) in the Company’s Consolidated Financial Statements. Beginning with cumulative equity affected as of December 31, 2010, the audited consolidated financial statements for the year ended December 31, 2011 have been restated, as have the six unaudited quarterly consolidated interim reports for the calendar years 2011 and 2012. The Company’s audited consolidated financial statements for the year ended 2012 and 2011 (restated), reported in this filing, present the NCI.

VICTORY ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

ASSETS	12/31/2011 As Originally Reported	12/31/2011 Restatement Adjustments	12/31/2011 As Restated	12/31/2010 As Originally Reported	12/31/2010 Restatement Adjustments	12/31/2010 As Restated
Current Assets						
Cash and cash equivalents	$ 475,623	$ -	475,623	$ 111,572	$ -	$ 111,572
Accounts receivable - less allowance for doubtful accounts of $200,000, and $0 for 2012 and 2011, respectively	79,185	-	79,185	74,828	-	74,828
Prepaid Expenses	29,555	-	29,555	24,898	-	24,898
Total current assets	584,363	-	584,363	211,298	-	211,298
Fixed Assets						
Furniture and equipment	10,623	-	10,623	2,294	-	2,294
Accumulated depreciation	(3,550)	-	(3,550)	(2,294)	-	(2,294)
Total furniture and fixtures, net	7,073	-	7,073	-	-	-
Option to acquire leases and mineral rights	-	-	-	25,000	-	25,000
Producing oil and natural gas properties, net of impairment	2,019,792	114,778 d	2,134,570	1,466,813	114,778 d	1,581,591
Accumulation depletion	(1,093,063)	(6,148)e	(1,099,211)	(953,084)	-	(953,084)
Total oil and gas properties, net	926,729	108,630	1,035,359	538,729	114,778	653,507
Other Assets - Funds held at court	$ -	$ -	-	$ 13,006	$ -	$ 13,006
Total Assets	$ 1,518,165	$ 108,630	$ 1,626,795	$ 763,033	$ 114,778	$ 877,811
LIABILITIES AND STOCKHOLDERS ' EQUITY						
Current Liabilities						
Accounts payable	$ 326,973	$ -	326,973	$ 342,285	$ -	$ 342,285
Accrued interest	150,267	-	150,267	10,501	-	10,501
Accrued liabilities	179,979	-	179,979	74,088	-	74,088
Accrued liabilities - related parties	-	-	-	50,000	-	50,000

Line of credit - bank	-	-	-	68,667	-	68,667
Amounts due former officer	-	-	-	-	404,624 f	404,624
Liability for unauthorized preferred stock issued	32,164	-	32,164	85,654	-	85,654
Total current liabilities	689,383	-	689,383	631,195	404,624	1,035,819
Other Liabilities						
Senior secured convertible debenture, net of debt discount	632,534	-	632,534	127,338	-	127,338
Deferred tax liability	748,763	(748,763) g	-	238,000	(238,000) g	-
Asset retirement obligations	30,004	-	30,004	27,282	-	27,282
Total long term liabilities	1,411,301	(748,763)	662,538	392,620	(238,000)	154,620
Total liabilities	2,100,684	(748,763)	1,351,921	1,023,815	166,624	1,190,439
Stockholders' Equity						
Common stock, $0.001 par value, 47,500,000 shares authorized, 7,647,494 shares and 2,740,734 shares issued and outstanding for 2011 and 2010, respectively	382,308	-	382,308	136,720	-	136,720
Additional paid-in capital	35,126,462	(8,499,240) a	26,627,222	31,740,090	(9,611,210) a	22,128,880
Accumulated deficit	(36,091,289)	7,615,700 b	(28,475,589)	(32,137,592)	7,368,005 b	(24,769,587)
Total Victory Energy Corporation stockholders' equity	(582,519)	(883,540)	(1,466,059)	(260,782)	(2,243,205)	(2,503,987)
Non-controlling interest	-	1,740,933	1,740,933	-	2,191,359	2,191,359
Total stockholder's equity (deficit)	(582,519)	857,393	274,874	(260,782)	(51,846)	(312,628)
Total Liabilities and Stockholder's Equity	$ 1,518,165	$ 108,630	$ 1,626,795	$ 763,033	$ 114,778	$ 877,811

a: Partnership contributions and distributions from January 1, 2008 through December 31, 2010 and tax provisions.

b: Cumulative change in equity due to non-controlling interest from January 1, 2008 through December 31, 2010 and PCAOB adjustments.

c: Non-controlling interest associated with net losses through March 31, 2011 and PCAOB adjustments.

d: Adjustment to correct a material misstatement of impairment.

e: Adjustment to correct a material misstatement of depreciation.

f: Adjustment for liability due to former officer which was not settled as of December 31, 2010.

g: Adjustment for tax provision.

VICTORY ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	12/31/2011			
	As Originally Reported	Restatement Adjustments		As Restated
Revenues				
Oil and gas sales	$305,180	$ -		$305,180
Total revenues	305,180	-		305,180
Operating Expenses:				
Lease operating costs	121,580	-		121,580
Production taxes	39,156	-		39,156
Exploration	559,523	-		559,523
General and administrative	2,094,768	-		2,094,768
Impairment of assets	102,579	-		102,579
Depreciation, depletion and accretion	76,525	6,148	a	82,673
Total operating expenses	2,994,131	6,148		3,000,279
Income (Loss) from operations	(2,688,951)	(6,148)		(2,695,099)
Other Income (Expense):				
Gain on settlement with former officer	-	404,624	b	404,624
Interest expense	(1,815,038)	-		(1,815,038)
Total other income and expense	(1,815,038)	404,624		(1,410,414)
NET INCOME (LOSS) BEFORE TAX BENEFIT	(4,503,989)	398,476		(4,105,513)
TAX BENEFIT	550,292	(550,292)	c	-
NET INCOME (LOSS)	(3,953,697)	(151,816)		(4,105,513)
Less: net loss attributable to non-controlling interest	-	399,511		399,511
Net loss attributable to Victory Energy Corporation	$(3,953,697)	$ 247,695		$(3,706,002)
Weighted average shares, basic and diluted	5,281,307			5,281,307
Net loss per share, basic and diluted	$(0.75)			$(0.70)

a: Adjustment to correct a material misstatement of depreciation.
b: Adjustment for liability due to former officer which was settled as of March 24, 2011.
c: Adjustment for tax provision.

Use of Estimates:

The preparation of our consolidated financial statements in conformity with U.S. Generally Accepted Accounting Principles ("GAAP") requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Estimates are used primarily when accounting for depreciation, depletion, and amortization ("DD&A") expense, property costs, estimated future net cash flows from proved reserves, cost to abandon oil and natural gas properties, taxes, accruals of capitalized costs, operating costs and production revenue, capitalized general and administrative costs and interest, insurance recoveries, effectiveness and estimated fair value of derivative positions, the purchase price allocation on properties acquired, various common stock, warrants and option transactions, and contingencies.

Oil and Natural Gas Properties:

We follow the successful efforts method of accounting for oil and natural gas properties. Under this method, all costs associated with property acquisitions, successful exploratory wells, all development wells, including dry hole development wells, and asset retirement obligation assets are capitalized. Additionally, interest is capitalized while wells are being drilled and the underlying property is in development. Costs of exploratory wells are capitalized pending determination of whether each well has resulted in the discovery of proved reserves. Oil and natural gas mineral leasehold costs are capitalized as incurred. Items charged to expense generally include geological and geophysical costs, costs of unsuccessful exploratory wells, and oil and natural gas production costs. Capitalized costs of proved properties including associated salvage are depleted on a well-by-well or field-by-field (common reservoir) basis using the units-of-production method based upon proved producing oil and natural gas reserves. The depletion rate is the current period production as a percentage of the total proved producing reserves. The depletion rate is applied to the net book value of property costs to calculate the depletion expense. Proved reserves materially impact depletion expense. If the proved reserves decline, then the depletion rate (the rate at which we record depletion expense) increases, reducing net income. Dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs with gain or loss recognized upon sale. A gain (loss) is recognized to the extent the sales price exceeds or is less than original cost or the carrying value, net of impairment. Oil and natural gas properties are also reviewed for impairment at the end of each reporting period. Unproved property costs are excluded from depleatable costs until the related properties are developed. See impairment discussed in "Long-lived assets and intangible assets" below.

We depreciate other property and equipment using the straight-line method based on estimated useful lives ranging from five to 10 years.

The Company recorded impairment expense of $344,353 and $102,579 for 2012 and 2011 respectively, upon determining that the oil and natural gas properties were impaired.

Long-lived Assets and Intangible Assets

The Company accounts for intangible assets in accordance with ASC 360, "Property, Plant and Equipment". Intangible assets that have defined lives are subject to amortization over the useful life of the assets. Intangible assets held having no contractual factors or other factors limiting the useful life of the asset are not subject to amortization but are reviewed at least annually for impairment or when indicators suggest that impairment may be needed. Intangible assets are subject to impairment review at least annually or when there is an indication that an asset has been impaired.

For unproved property costs, management reviews these investments for impairment on a property-by-property basis if a triggering event should occur that may suggest that impairment may be required.

The Company reviews its long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If the carrying amount of the asset, including any intangible assets associated with that asset, exceeds its estimated future undiscounted net cash flows, the Company will recognize an impairment loss equal to the difference between its carrying amount and its estimated fair value. The fair value used to calculate the impairment for producing oil and natural gas field that produces from a common reservoir is first determined by comparing the undiscounted future net cash flows associated with total proved properties to the carrying value of the underlying evaluated property. If the cost of the underlying evaluated property is in excess of the undiscounted future net cash flows, the future net cash flows are discounted at 10%, which the Company believes approximates fair value, to determine the amount of impairment.

Asset Retirement Obligations:

U.S. GAAP requires us to record our estimate of the fair value of liabilities related to future asset retirement obligations in the period the obligation is incurred. Asset retirement obligations relate to the removal of facilities and tangible equipment at the end of an oil and natural gas property's useful life. The application of this rule requires the use of management's estimates with respect to future abandonment costs, inflation, market risk premiums, useful life and cost of capital. U.S. GAAP requires that our estimate of our asset retirement obligations does not give consideration to the value the related assets could have to other parties.

The following table is a reconciliation of the ARO liability for continuing operations for the twelve months ended December 31, 2012 and 2011.

	Years Ended December 31,	
	2012	2011
Asset retirement obligation at beginning of period	$ 30,004	$ 27,282
Liabilities incurred	7,002	1,269
Revisions to previous estimates	0	0
Accretion expense	2,899	1,453
Asset retirement obligation at end of period	$ 39,905	$ 30,004

Other Property and Equipment:

Our office equipment in Austin, Texas is being depreciated on the straight-line method over their estimated useful life of 5 to 7 years.

Cash and Cash Equivalents:

The Company considers all liquid investments with a maturity of three months or less from the date of purchase that are readily convertible into cash to be cash equivalents. The Company had no cash equivalents at December 31, 20l2 and December 31, 2011, respectively.

Accounts Receivable:

Our accounts receivable are primarily from purchasers of natural gas and oil and exploration and production companies which own an interest in properties we operate.

Allowance for Doubtful Accounts:

The Company recognizes an allowance for doubtful accounts to ensure trade receivables are not overstated due to un-collectability. Allowance for doubtful accounts are maintained for all customers based on a variety of factors, including the length of time receivables are past due, macroeconomic conditions, significant one-time events and historical experience. An additional allowance for individual accounts is recorded when they become aware of a customer's inability to meet its financial obligations, such as in the case of bankruptcy filings or deterioration in the customer's operating results or financial position. If circumstances related to customers change, estimates of the recoverability of receivables would be further adjusted. As of December 31, 2012, the Company has deemed $200,000 from the sale of oil and gas properties associated with the Jones County prospect, to be uncollectible and thus, has recorded this amount as an allowance for doubtful accounts.

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Asset Impairment:

At December 31, 2012 and 2011, the carrying value of the Company's financial instruments such as prepaid expenses and payables approximated their fair values based on the short-term maturities of these instruments. The carrying value of other long-term liabilities approximated their fair values because the underlying interest rates approximate market rates at the balance sheet dates. Management believes that due to the Company's current credit worthiness, the fair value of long-term debt could be less than the book value; however, due to current market conditions and available information, the fair value of such debt is not readily determinable. Financial Accounting Standard Board ("FASB") ASC Topic 820 established a hierarchical disclosure framework associated with the level of pricing observability utilized in measuring fair value. This framework defined three levels of inputs to the fair value measurement process and requires that each fair value measurement be assigned to a level corresponding to the lowest level input that is significant to the fair value measurement in its entirety. The three broad levels of inputs defined by

FASB ASC Topic 820 hierarchy are as follows:

Level 1 - quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date;

Leve1 2 - inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Leve1 2 input must be observable for substantially the full term of the asset or liability; and

Leve1 3 - unobservable inputs for the asset or liability. These unobservable inputs reflect the entity's own assumptions about the assumptions that market participants would use in pricing the asset or liability and are developed based on the best information available in the circumstances (which might include the reporting entity's own data).

The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flows techniques and based on internal estimates of future retirement costs associated with proved oil and gas properties. Inputs used in the calculation of asset retirement obligations include plugging costs and reserve lives. A reconciliation of Victory’s asset retirement obligations is presented in Note 1.

During 2012, proved oil and gas properties with a carrying value of $395,463 were written down, based upon engineering estimates, to their fair value of $51,110, resulting in impairment charges of $344,353. During 2011, proved oil and gas properties with a carrying value of $557,034 were written down, based upon Level 3 inputs, to their fair value of $454,455, resulting in impairment charges of $102,579. Significant Level 3 assumptions associated with the calculation of discounted cash flows used in the impairment analysis include Victory’s estimate of future crude oil and natural gas prices, production costs, development expenditures, anticipated production of proved reserves, appropriate risk-adjusted discount rates and other relevant data; primarily derived from a third party independent reserve report.

Revenue Recognition:

The Company uses the sales method of accounting for oil and natural gas revenues. Under this method, revenues are recognized based on actual volumes of gas and oil sold to purchasers. The volumes sold may differ from the volumes to which the Company is entitled based on our interests in the properties. Differences between volumes sold and entitled volumes create oil and natural gas imbalances which are generally reflected as adjustments to reported proved oil and natural gas reserves and future cash flows in their supplemental oil and natural gas disclosures. If their excess takes of natural gas or oil exceed their estimated remaining proved reserves for a property, a natural gas or oil imbalance liability is recorded in the Consolidated Balance Sheets.

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Concentrations:

There is a ready market for the sale of crude oil and natural gas. During 2012 and 2011, our gas field and our producing wells sold their respective gas and oil production to one purchaser for each field or well. However, because alternate purchasers of oil and natural gas are readily available at similar prices, we believe that the loss of any of our purchasers would not have a material adverse effect on our financial results.

Earnings per Share:

Basic earnings per share are computed using the weighted average number of common shares outstanding at December 31, 2012, the weighted average number of common shares outstanding was 23,292,609. Diluted earnings per share reflect the potential dilutive effects of common stock equivalents such as options, warrants and convertible securities. Given the historical and projected future losses of the Company, all potentially dilutive common stock equivalents are considered anti-dilutive. As of December 31, 2012, the Company had 27,563,619 shares of common stock shares outstanding and 2,982,218 of common stock equivalents, comprised of 137,932 unconverted Preferred B shares, 2,624,286 warrants outstanding, and 220,000 stock options outstanding, which were anti-dilutive and not included in the earnings per share calculation. As of December 31, 2011, the weighted average number of common shares outstanding was 5,281,307. As of December 31, 2011, the Company had 7,647,494 shares of common stock outstanding, and 783,145 of common stock equivalents comprised of 603,145 warrants outstanding and 180,000 stock options outstanding, which were anti-dilutive and not included in the earnings per share calculation.

Income Taxes:

The Company accounts for income taxes in accordance with ASC 740 “Income Taxes” which requires an asset and liability approach for financial accounting and reporting of income taxes. Deferred income taxes reflect the impact of temporary differences between the amount of assets and liabilities for financial reporting purposes and such amounts as measured by tax laws and regulations. Deferred tax assets include tax loss and credit carry forwards and are reduced by a valuation allowance if, based on available evidence, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

Stock Based Compensation:

The Company applies ASC 718, “Compensation-Stock Compensation” to account for its issuance of options and warrants to key partners, directors and officers. The standard requires all share-based payments, including employee stock options, warrants and restricted stock, be measured at the fair value of the award and expensed over the requisite service period (generally the vesting period). The fair value of options and warrants granted to key partners, directors and officers is estimated at the date of grant using the Black-Scholes option pricing model by using the historical volatility of the Company’s stock price. The calculation also takes into account the common stock fair market value at the grant date, the exercise price, the expected life of the common stock option or warrant, the dividend yield and the risk-free interest rate.

The Company from time to time may issue stock options, warrants and restricted stock to acquire goods or services from third parties. Restricted stock, options or warrants issued to third parties are recorded on the basis of their fair value, which is measured as of the date issued. The options or warrants are valued using the Black-Scholes option pricing model on the basis of the market price of the underlying equity instrument on the “valuation date,” which for options and warrants related to contracts that have substantial disincentives to non-performance, is the date of the contract, and for all other contracts is the vesting date. Expense related to the options and warrants is recognized on a straight-line basis over the shorter of the period over which services are to be received or the vesting period.

The Company recognized stock-based directors fee and service incentive fee compensation expense from warrants granted to directors for the years ended December 31, 2012 and 2011 of $40,500 and $312,000, respectively.

The Company recognized stock-based officer compensation expense from stock options granted to officers of the company for the twelve months ended December 31, 2012 and 2011 of $147,093 and $152,700 respectively.

Going Concern:

The accompanying consolidated financial statements have been prepared assuming the Company will continue as a going concern, which contemplates the realization of assets and satisfaction of liabilities in the normal course of business. As presented in the consolidated financial statements, the Company has incurred a net loss of $6.7 million and $3.7 million during the years ended December 31, 2012 and 2011, respectively. $4.0 million and $1.8 million, during the years ended December 31, 2012 and 2011, respectively, was for non-cash expenses including the amortization of the debt discount and warrants associated with the Company's 10% Senior Secured Convertible Debentures, the unamortized portion of the debt discount recognized on the conversion of the 10% Senior Secured Convertible to common stock on February 29, 2012, depletion, depreciation, impairment, warrants given for services, and stock based compensation.

The cash proceeds from the sale of the Company's 10% Senior Secured Convertible Debentures and new contributions to the Aurora partnership by The Navitus Energy Group ("Navitus") have allowed the Company to continue operations and invest in new oil and natural gas properties. Management anticipates that operating losses will continue in the near term until new wells are drilled, successfully completed and incremental production increases revenue. As of December 31, 2012 on a year to date basis the Company has invested $1,012,899 in the acquisition of land or the drilling of wells.

The Company remains in active discussions with Navitus and others related to longer term financing required for our capital expenditures planned for 2013. Without additional outside investment from the sale of equity securities and/or debt financing, our capital expenditures and overhead expenses must be reduced to a level commensurate with available cash flows.

The accompanying consolidated financial statements are prepared as if the Company will continue as a going concern. The consolidated financial statements do not contain adjustments, including adjustments to recorded assets and liabilities, which might be necessary if the Company were unable to continue as a going concern.

Note 2 - Recent Accounting Pronouncements

Recently Issued Accounting Standards

In September 2011, the FASB issued Accounting Standard Update ("ASU") No. 2011-08, "Intangible – Goodwill and Other (Topic 350), Testing Goodwill for Impairment". The ASU provides an option for an entity to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If, after assessing the totality of events or circumstances, an entity determines it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then performing the two-step impairment test is unnecessary. However, if an entity concludes otherwise, then it is required to perform the first step of the two-step impairment test by calculating the fair value of the reporting unit and comparing the fair value with the carrying amount of the reporting unit, as described in paragraph 350-20-35-4. If the carrying amount of a reporting unit exceeds its fair value, then the entity is required to perform the second step of the goodwill impairment test to measure the amount of the impairment loss, if any. Under the ASU, an entity has the option to bypass the qualitative assessment for any reporting unit in any period and proceed directly to performing the first step of the two-step goodwill impairment test. An entity may resume performing the qualitative assessment in any subsequent period. This ASU is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011, and the adoption of this ASU did not have a material effect on the consolidated financial statements.

In June 2011, the FASB issued ASU No. 2011-05, “Comprehensive Income (Topic 220), and Presentation of Comprehensive Income”. The ASU provides an entity has the option to present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In both choices, an entity is required to present each component of net income along with total net income, each component of other comprehensive income along with a total for other comprehensive income, and a total amount for comprehensive income. In a single continuous statement, the entity is required to present the components of net income and total net income, the components of other comprehensive income and a total for other comprehensive income, along with the total of comprehensive income in that statement. In the two-statement approach, an entity is required to present components of net income and total net income in the statement of net income. The statement of other comprehensive income should immediately follow the statement of net income and include the components of other comprehensive income and a total for other comprehensive income, along with a total for comprehensive income. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011, and the adoption of this ASU did not have a material effect on the consolidated financial statements.

Note 3 – Oil and natural gas properties

Oil and natural gas properties are comprised of the following:

	December 31, 2012	December 31, 2011
Oil and natural gas properties	$ 776,317	$ 101,259
Drilling and work in process	208,728	268,436
Proved property - purchased gas wells	3,130,100	3,130,100
Proved property - drilled gas wells	1,753,026	1,753,026
Producing oil wells	400,535	222,598
Total oil and natural gas properties, at cost	6,268,706	5,475,419
Less: accumulated impairment	(3,685,202)	(3,340,849)
Oil and natural gas properties, net impairment	2,583,504	2,134,570
Less: accumulated depletion	(1,145,514)	(1,099,211)
Oil and natural gas properties, net	1,437,990	1,035,359

Depletion, depreciation, and accretion expense for the years ended December 31, 2012 and 2011 was $51,172 and $82,673, respectively. During the years ended December 31, 2012 and 2011, the Company recorded impairment losses of $344,353 and $102,579 respectively.

Note 4 – Senior Secured Convertible Debentures

All share references have been adjusted to reflect a 50:1 reverse stock split by the Company on January 12, 2012.

During the years ended December 31, 2011 and December 31, 2012 the Company raised $4,935,000 from accredited investors via 10% Senior Secured Convertible Debentures. Specifically the Company raised $3,120,000 in 2011 and $1,815,000 on February 29, 2012. These debentures were converted to 19,505,523 shares of the Company's common stock in accordance with the terms of the debenture.

Terms of the 10% Senior Secured Convertible Debenture are as follows:

§ The maturity date of the 10% Senior Secured Convertible Debentures is September 30, 2013, but may be extended at the sole discretion of the Company to December 31, 2013.

§ In connection with the Debenture offering, the Company also issued five (5) year warrants to purchase an aggregate of 104,400 shares of the Company's common stock at an exercise price of $0.25 per share, subject to customary adjustments for stock splits, stock dividends, recapitalizations and the like.

§ The Company has the right to force conversion of the 10% Senior Secured Convertible Debentures under certain terms and conditions.

§ The 10% Senior Secured Convertible Debentures are secured under the terms of a Security Agreement by a security interest in all of the Company's personal property. The relative fair value of the warrants and beneficial conversion features of the 10% Senior Secured Convertible Debentures were determined at the time of issuance using the methodology prescribed by current accounting guidance.

The Company converted the debentures in two phases as follows:

1. During the year ended December 31, 2011 $1,112,500 of the outstanding 10% Senior Secured Convertible Debentures were converted to 4,445,000 shares of the Company's common stock in accordance with their terms.

2. In February 2012 the remaining $4,649,775 of the outstanding 10% Senior Secured Convertible Debentures was converted to 19,505,523 shares of the Company's common stock in accordance with their terms.

Accounting for the Debentures:

- The Company determined the initial fair value of the 10% beneficial conversion feature was approximately $1.7 million.

- The initial fair value of the warrants of $61,649 and the beneficial conversion feature of $1,753,351 were recorded by the Company as a discount of $1,815,000, for the year ended December 31, 2012, and which the Company is amortizing to interest expense over the life of the 10% Senior Secured Convertible Debentures.

- The beneficial conversion feature of $3,120,000 was recorded by the Company as a discount of $3,120,000 for the year ended December 31, 2011, which the Company amortized to interest expense over the life of the 10% Senior Convertible Debentures.

Period Ended	Convertible Debentures Raised (Converted)	Beneficial Conversion Value
12/31/2010	$ 827,275	$ 700,708
3/31/2011	$ 910,000	$ 910,000
6/30/2011	$ 882,500	$ 882,500
9/30/2011	$ 477,500	$ 477,500
12/31/2011	$ 850,000	$ 850,000
	$ 3,947,275	$ 3,820,708
Converted	$ (1,112,500)	$ (1,618,467)
12/31/2011	$ 2,834,775	$ 2,202,241
12/31/2012	$ 1,815,000	$ 1,753,359
Subtotal	$ 4,649,775	$ 3,955,600
Converted		$ (3,661,781)
2/29/2012	$ (4,649,775)	$ (293,819)
Outstanding	$ 0	$ 0

The senior secured convertible 10% Senior Secured Convertible Debentures consists of the following at December 31:

	December 31, 2012	2011
Convertible debenture, interest at 10% per annum payable quarterly, due September 30, 2013 with separable warrants	$ 2,834,775	$ 3,395,000
Convertible debenture, interest at 10% per annum payable quarterly, due September 30, 2013 issued in exchange for notes payable and accrued interest to related party	1,815,000	552,275
Subtotal	4,649,775	3,947,275
Converted to common stock	(4,649,775)	(1,112,500)
Subtotal	0	2,834,775
Unamortized debt discount	0	(2,202,241)
Net book value	$ 0	$ 632,534

Note 5 – Liability for Unauthorized Preferred Stock Issued

During the year ended December 31, 2006, the Company authorized the issuance of 10,000,000 shares of Preferred Stock, convertible at the shareholder's option to common stock at the rate of 100 shares of common stock for every share of preferred stock. During the year ended December 31, 2006, the Company issued 715,517 shares of preferred stock for cash of $246,950. The Company subsequently issued additional preferred stock and had several preferred shareholders convert their shares into common stock during the years ended December 31, 2009, 2008, and 2007.

The Company's legal counsel determined that the preferred shares had not been duly authorized by the State of Nevada. Since the Company had issued and received consideration for the preferred stock, notwithstanding that the stock was not legally authorized, the Company has presented the preferred stock as a liability in the consolidated balance sheets. The Company has offered to settle the debt with the remaining holders of the unauthorized preferred stock by honoring the terms of conversion of two shares of preferred stock into 100 shares of common stock. The Company intends to cancel the preferred stock once all remaining preferred stockholders have converted.

There were 68,966 and 238,966 shares of unconverted preferred stock outstanding at December 31, 2012 and December 31, 2011, respectively. The Company needs approximately 138,000 common shares in order to settle the outstanding debt as stated below.

The remaining liability for the unconverted preferred stock is based on the original cash tendered and consisted of the following as of:

	December 31, 2012	2011
Liability for unauthorized preferred stock	$ 9,283	$ 32,164

Note 6 – Income Taxes

There was no provision for (benefit of) income taxes for the years ended December 31, 2012 and 2011 (restated), after the application of ASC 740 "Income Taxes".

The Internal Revenue Code of 1986, as amended, imposes substantial restrictions on the utilization of net operating losses in the event of an "ownership change" of a corporation. Accordingly, a company's ability to use net operating losses may be limited as prescribed under Internal Revenue Code Section 382 ("IRC Section 382"). Events which may cause limitations in the amount of the net operating losses that the company may use in any one year include, but are not limited to, a cumulative ownership change of more than 50% over a three-year period. There have been transactions that have changed the Company's ownership structure since inception that may have resulted in one or more ownership changes as defined by the IRC section 382. The Company's stock issuance arising from convertible debt in 2012 has resulted in a limitation of net operating loss carry forward for the Company of $13,807,335 over a 20 year period.

At December 31, 2012, the Company had available Federal operating loss carry forwards to reduce future taxable income. The Federal net operating loss carry forwards available were approximately $13,807,335 as of December 31, 2012. The Federal net operating loss carry forward begins to expire in 2027. Capital loss carryovers may only be used to offset capital gains.

Given the Company's history of net operating losses, management has determined that it is more-likely-than-not the Company will not be able to realize the tax benefit of the net operating loss carry forwards. ASC 740 requires that a valuation allowance be established when it is more likely than not that all or a portion of deferred tax assets will not be realized.

Accordingly, the Company has recorded a full valuation allowance against its net deferred tax assets at December 31, 2012 and 2011, respectively. Upon the attainment of taxable income by the Company, management will assess the likelihood of realizing the deferred tax benefit associated with the use of the net operating loss carry forwards and will recognize a deferred tax asset at that time.

Significant components of the Company's deferred income tax assets are as follows:

	12/31/2012	12/31/2011
Net operating loss carryforwards	$ 4,694,494	$ 4,406,441
Accounts payable and accrued expenses	92,891	234,390
Equity based expenses	1,700,507	1,460,400
Accounts receivable and prepaid expenses	(76,899)	(36,972)
Deferred taxes	6,410,993	6,064,259
Valuation allowance	(6,410,993)	(6,064,259)
Net Deferred Income Tax Assets	$ -	$ -

Reconciliation of the effective income tax rate to the U.S. statutory rate is as follows:

	12/31/2012	12/31/2011
Book loss	-34.00 %	-34.00 %
Meals and entertainment	0.02	0.03
Debt discount accretion	18.47	14.84
Net operating loss reduction due IRC 382	10.37	-
Change in valuation allowance	5.14	19.13
Effective income tax rate	0.00 %	0.00 %

ASC 740 provides guidance which addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the consolidated financial statements. Under the current accounting guidelines, the Company may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the consolidated financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. As of December 31, 2012 and 2011 the Company does not have a liability for unrecognized tax benefits.

The Company has elected to include interest and penalties related to uncertain tax positions as a component of income tax expenses. To date, no penalties or interest has been accrued.

Tax years 2010 forward are open and subject to examination by the Federal taxing authority. The Company is not currently under examination and it has not been notified of a pending examination.

Note 7 – Stockholders’ Equity

Common stock

The Company estimates the fair value of employee stock options and warrants granted using the Black-Scholes Option Pricing Model. Key assumptions used to estimate the fair value of warrants and stock options include the exercise price of the award, the fair value of the Company’s common stock on the date of grant, the expected warrant or option term, the risk free interest rate at the date of grant, the expected volatility and the expected annual dividend yield on the Company’s common stock.

During the year ended December 31, 2012, the Company granted 2,044,591 warrants for board services and consulting services. The Company has valued the warrants for services using the Black Scholes Option Pricing Model, at $496,979. The warrants issued for board services were 120,000 valued at $73,800, warrants issued for third party services were 1,904,291 with a fair value at $423,179, and warrants exercised for cash were 20,602 valued at $5,075. 3,150 warrants were cancelled during 2012.

During the year ended December 31, 2011, the Company granted 114,000 warrants for board services and 152,400 warrants for consulting services valued with the Black Scholes pricing model at $312,000.

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Note 8 – Warrants for Stock

At December 31, 2012 and 2011 warrants outstanding for common stock of the Company were as follows:

	Number of Shares Underlying Warrants	Weighted Average Exercise Price
Balance at January 1, 2012	603,145	$ 3.26
Granted	2,044,591	0.52
Exercised	(20,300)	0.25
Cancelled	(3,150)	0.50
Balance at December 31, 2012	2,624,286	$ 1.15

	Number of Shares Underlying Warrants	Weighted Average Exercise Price
Balance at January 1, 2011 (Restated for 1:50 stock split)	336,745	$ 5.40
Granted	266,400	0.55
Exercised	-	-
Cancelled	-	-
Balance at December 31, 2011	603,145	$ 3.26

The following table summarizes information about underlying outstanding warrants for common stock of the Company outstanding and exercisable as of December 31, 2012:

	Warrants Outstanding			Warrants Exercisable	
Range of Exercise Prices	Number of Shares Underlying Warrants	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (in years)	Number of Shares Underlying Warrants	Weighted Average Exercise Price
$ 12.50 – $17.50	125,245	$ 13.03	8.6	125,245	$ 13.03
$ 0.25 - $2.50	2,499,041	$ 0.56	4.2	2,499,041	$ 0.56
	2,624,286			2,624,286	

The following table summarizes information about underlying outstanding warrants for common stock of the Company outstanding and exercisable as of December 31, 2011:

	Warrants Outstanding			Warrants Exercisable	
Range of Exercise Prices	Number of Shares Underlying Warrants	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (in years)	Number of Shares Underlying Warrants	Weighted Average Exercise Price
12.50 – $$17.50	125,245	$13.03	9.6	125,245	$13.03
0.25 - $$2.50	477,900	$ 0.69	3.8	477,900	$ 0.69
	603,145			603,145	

All future changes in the fair value of these warrants will be recognized currently in earnings until such time as the warrants are exercised or expire. These common stock purchase warrants do not trade in an active securities market, and as such, we estimate the fair value of these warrants using the Black-Scholes Option Pricing Model using the following assumptions:

	2012	2011
Risk free interest rates	.62% - 1.04 %	.81% - 2.40 %
Expected life	5 years	5 years
Estimated volatility	514.9% - 577.0 %	673.3% - 693.6 %
Dividend yield	0 %	0 %

Expected volatility is based primarily on historical volatility. Historical volatility was computed using daily pricing observations for recent periods that correspond to the remaining life of the warrants. We believe this method produces an estimate that is representative of our expectations of future volatility over the expected term of these warrants. We currently have no reason to believe future volatility over the expected remaining life of these warrants is likely to differ materially from historical volatility. The expected life is based on the remaining term of the warrants. The risk-free interest rate is based on U.S. Treasury securities.

At December 31, 2012 and 2011 the aggregate intrinsic value of the warrants outstanding and exercisable was $43,515 and $417,060, respectively. The intrinsic value of a warrant is the amount by which the market value of the underlying warrant exercise price exceeds the market price of the stock at December 31 of each year.

Note 9 – Stock Options

The following table summarizes stock option activity in the Company's stock-based compensation plans for the year ended December 31, 2012. All options issued were non-qualified stock options. All options have been restated for the 1:50 reverse stock split on January 12, 2012.

	Number of Shares	Weighted Average Exercise Price	Aggregate Intrinsic Value (1)	Number of Shares Exercisable	Weighted Average Fair Value At

							Date of Grant	
Outstanding at December 31, 2010	-		-		-	-		
Granted at Fair Value	180,000	$	.83			80,000	$	1.35
Exercised	-		-					
Cancelled	-		-			-		
Outstanding at December 31, 2011	180,000	$	.83	$	147,000	80,000		
Granted at Fair Value	130,000	$	.84			45,000	$	1.32
Exercised	-		-					
Cancelled	90,000	$	.83			-		
Outstanding at December 31, 2012	220,000	$	.84	$	0	125,000		

(1) The intrinsic value of a stock option is the amount by which the market value of the underlying stock exceeds the exercise price of the option at December 31, 2012. If the exercise price exceeds the market value, there is no intrinsic value.

The fair value of the stock option grants are amortized over the respective vesting period using the straight-line method and assuming no forfeitures and cancelations. The Company has no historical experience to estimate forfeitures and cancellations.

Compensation expense related to stock options included in Exploration Expense and General and Administrative Expense in the accompanying consolidated statement of operations for the years ended December 31, 2012 and December 31, 2011, was $191,719, and $108,000, respectively. The estimated unrecognized compensation cost from unvested options as of December 31, 2012 was approximately $64,156, which is expected to be recognized over a period of 1.2 years.

Stock options are granted at the fair market value of the Company's common stock on the date of grant. Options granted to officers and other employees vest immediately or over 24 months as provided in the option at the date of grant.

The fair value of each option granted in 2012 and 2011 was estimated using the Black-Scholes Option Pricing Model. The following assumptions were used to compute the weighted average fair value of options granted during the periods presented.

	2012		2011	
Expected life of option	0 to 6 years		0 to 6 years	
Risk free interest rates	.8% - .8	%	.9	%
Estimated volatility	514.9% - 585.0	%	685.1	%
Dividend yield	0.0	%	0.0	%

The following table summarizes information about stock options outstanding at December 31, 2012:

Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Aggregate Intrinsic Value (1)	Number Exercisable	Weighted Average Exercise Price of Exercisable Options	Aggregate Intrinsic Value (1)
$ .50 - $1.00	220,000	4.1	$ .84	$ 0	164,378	$ .78	$ 0

(1) The intrinsic value of a stock option is the amount by which the market value of the underlying stock exceeds the exercise price of the option at December 31, 2012. If the exercise price exceeds the market value, there is no intrinsic value.

The following table summarizes information about options outstanding at December 31, 2011:

Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Aggregate Intrinsic Value (1)	Number Exercisable	Weighted Average Exercise Price of Exercisable Options	Aggregate Intrinsic Value

$ 0.01 - $0.02	180,000	4.7	$ .85	$ 147,000	80,000	$ .65	$ 82,000

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A summary of the Company's non-vested stock options at December 31, 2012 and December 31, 2011 and changes during the years are presented below.

Non-Vested Stock Options	Options	Weighted Average Grant Date Fair Value
Non-Vested at December 31, 2011	100,000	$ 1.35
Granted	85,000	$ 1.36
Vested	(69,378)	$ 1.26
Forfeited	(60,000)	$ 1.65
Non-Vested at December 31, 2012	55,622	$ 1.15

Non-Vested Stock Options	Options	Weighted Average Grant Date Fair Value
Non-Vested at December 31, 2010	0	$ 0.00
Granted	180,000	$ 1.35
Vested	(80,000)	$ 1.26
Forfeited	0	$ 1.65
Non-Vested at December 31, 2011	100,000	$ 1.15

Note 10 – Commitments and Contingencies

Leases

Rent expense for the years ended December 31, 2012 and 2011 was $23,570 and $17,600, respectively. Future annual minimum payments under non-cancellable operating leases are $30,000 and $12,000 for the years ending December 31, 2013 and 2014, respectively.

Litigation

Cause No. 08-04-07047-CV; Oz Gas Corporation v. Remuda Operating Company, et al. v. Victory Energy Corporation.; In the 112th District Court of Crockett County, Texas.

Plaintiff Oz Gas Corporation sued Victory Energy Corporation and other parties for bad faith trespass, among other claims, regarding the drilling of two wells on lands that Oz Gas Corporation claims title to. Victory Energy Corporation has a 50% interest in one of the named wells involved in this lawsuit (that being well 155-2 on the Adams Baggett Ranch in Crockett County, Texas). The lawsuit was originally filed against other parties in April 2008, and Victory intervened in the case on November 18, 2009 to protect its interest in the 155-2 well.

The case was tried in February 2012. The Court found in favor of Oz and rendered verdict against Victory and the other defendants for the sum of $137,000, which was accrued at December 31, 2012. Victory Energy Corporation has appealed this decision to the 8th Court of Appeals in El Paso, Texas, and the case has been fully briefed and submitted. We believe that the trial verdict will be reversed on appeal and that Victory Energy Corporation's title to the 155-2 will be affirmed.

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Cause No. CV-47,230; James Capital Energy, LLC and Victory Energy Corporation v. Jim Dial, et al.; In the 142nd District Court of Midland County, Texas.

This lawsuit was filed on January 19, 2010 by James Capital Energy, LLC and Victory Energy Corporation against numerous parties for fraud, fraudulent inducement, negligent misrepresentation, breach of contract, breach of fiduciary duty, trespass, conversion and a few other related causes of action. This lawsuit stems from an investment made by Victory for the purchase of six wells on the Adams Baggett Ranch.

On December 9, 2010, Victory was granted an interlocutory Default Judgment against Defendants Jim Dial, 1st Texas Natural Gas Company, Inc., Universal Energy Resources, Inc., Grifco International, Inc., and Precision Drilling & Exploration, Inc. The total judgment amounted to $17.2 million. No amounts have been recorded for this matter as of December 31, 2012.

Recently Victory has added additional parties to this lawsuit. Discovery is ongoing in this case and no trial date has been set at this time.

Victory believes that it will be victorious against all the remaining Defendants in this case.

On October 20, 2011 Defendant Remuda filed a Motion to Consolidate and a Counterclaim against Victory. Remuda is seeking to consolidate this case with two other cases in which Remuda is the named Defendant. An objection to this motion was filed and the cases have not been consolidated. Additionally, we do not believe that the counterclaim made by Remuda has any legal merit.

Cause No. 10-09-07213; Perry Howell, et al. v. Charles Gary Garlitz, et al.; In the 112th District Court of Crockett County, Texas.

The above referenced lawsuit was filed on September 6, 2010. This lawsuit alleges that Cambrian Management, Ltd. and Victory Energy Corporation trespassed on lands owned by the Plaintiffs in the drilling of the Adams-Baggett 115-8 well in Crockett County, Texas.

Discovery is ongoing in this case and the case is set for trial in July 2014. Victory Energy Corporation believes that the claims have no merit and that it will prevail at trial.

Cause No. D-1-GN-13-00044; Aurora Energy Partners and Victory Energy Corporation v. Crooked Oaks; In the 261st District Court of Travis County, Texas.

The Company has yet to collect an installment balance of $200,000 for the sale of its Jones County, Texas oil and gas interests in May of 2012. The Company believes it will ultimately recover this receivable balance, but has provided for it as an allowance for doubtful accounts for the entire $200,000 balance, and has not included it in the net accounts receivable balance of the Company’s 2012 consolidated financial statements.

Note 11 - Related Party Transactions

During the year ended December 31, 2012, we incurred a total of $153,355 of accounting services with Miranda & Associates, owned by Robert Miranda, a director, a Professional Accountancy Corporation (“Miranda”). As of December 31, 2012, Miranda was owed $825 for these professional services.

During the year ended December 31, 2012 we incurred a total of $198,009 in legal fees with The McCall Firm. David McCall is the Company’s general counsel and a director, and is a partner in The McCall Firm. The fees are attributable to litigation involving the Company’s oil and natural gas operations in Texas. As of December 31, 2012, the Company owed The McCall Firm approximately $16,679 for these professional services.

On January 7, 2011, the Company entered into an Employment Agreement with Kenneth Hill, wherein he agreed to serve as Vice President and Chief Operating Officer of the Company. The term of the agreement began on January 10, 2011, and will end upon notice by either party. Mr. Hill will receive a base annual salary of $180,000 per year and he will participate in the Company’s employee benefit plans made available to its executive officers generally.

On January 7, 2011, the Company entered into an Employment Agreement with Stanley Lindsey, wherein he agreed to serve as Vice President of Exploration and Development of the Company. The term of the agreement began on January 10, 2011, and will end upon notice by either party. Mr. Lindsey will receive a base annual salary of $180,000 per year and he will participate in the Company's employee benefit plans made available to its executive officers generally. As of April 15, 2013, Stan Lindsey is no longer employed by the Company.

On December 28, 2011 the Company entered into an Employment Agreement with Mark Biggers, wherein he agreed to serve as Chief Financial Officer of the Company. The term of the agreement began on January 10, 2012. Effective November 28, 2012 Mark Biggers resigned from the Company due to personal reasons.

During the year ended December 31, 2011, we incurred a total of $549,471 of accounting, internal audit, CEO & CFO management, and income tax, and business turnaround consulting fees with Miranda & Associates, A Professional Accountancy Corporation ("Miranda"). Of these fees, $180,000 is attributable to the services of Robert Miranda as an executive officer of the Company. The balance of approximately $120,500 is related to the work done on the Company's SEC filings for 2007 through 2010 with the remaining balance of $248,971 related to internal audit, income tax, and advisory services provided by other members of the Miranda firm. As of December 31, 2011, Miranda & Associates was owed $66,230 for these professional services. Mr. Miranda also receives warrants for services as a director of the Company.

During the year ended December 31, 2011, we incurred a total of $210,332 in legal fees with The McCall Firm primarily for work in relation to the trespass law suits and other lawsuits related to the recovery of the malfeasance losses in 2008 and 2009. In November, 2011, David McCall, a principal in the The McCall Firm was appointed general counsel of the Company and was given a total of 90,000 with a fair value of approximately $132,000. As of December 31, 2011, The McCall Firm was owed $24,549 for these processional services. Mr. McCall also received warrants for services as a director of the Company.

Note 12 – Supplementary Financial Information on Oil and Natural Gas Exploration, Development and Production Activities (Unaudited)

The following disclosures provide unaudited information required by ASC 932, "Extractive Activities – Oil and Gas" on oil and natural gas producing activities. These disclosures include non-controlling interests in Aurora which is managed and owned 50% by Victory.

Results of operations from oil and natural gas producing activities (Successful Efforts Method)

The Company's oil and natural gas properties are located within the United States. The Company currently has no operations in foreign jurisdictions. Results of operations from oil and natural gas producing activities are summarized below for the years ended December 31:

	Years Ended December 31,	
	2012	2011
Revenues	$ 326,384	$ 305,180
Costs incurred:		
Dry hole costs	54,678	-
Exploration costs	266,514	559,523
Lease operating costs and production taxes	150,780	160,736
Impairment of oil and natural gas reserves	344,353	102,579

Costs incurred of asset retirement obligation	7,002	1,269
Depletion, depreciation and amortization	51,172	82,673
Totals, costs incurred	877,499	906,780
Pre-tax income (loss) from producing activities	(551,115)	(601,600)
Results of oil and natural gas producing activities (excluding overhead, income taxes, and interest costs)	$ (551,115)	$ (601,600)

Costs incurred in oil and natural gas property acquisition, exploration and development activities are summarized below for the years ended December 31:

	Years ended December 31,	
	2012	2011
Property acquisition and developmental costs:		
Development	$ 337,841	$ 219,700
Undrilled leaseholds	675,058	101,259
Asset retirement obligations	7,002	1,269
Totals costs incurred	$ 1,019,901	$ 322,228

Oil and natural gas reserves

Proved reserves are estimated quantities of oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can reasonably be expected to be recovered through existing wells with existing equipment and operating methods.

Proved oil and natural gas reserve quantities at December 31, 2012 and 2011 and the related discounted future net cash flows are based on estimates prepared by independent petroleum engineers. The reserves as of December 31, 2012 were derived from reserve estimates prepared by the independent reserve engineer. Such estimates have been prepared in accordance with guidelines established by the Securities and Exchange Commission. In 2009 the SEC issued guidance requiring oil and natural gas companies to calculate the value of proved reserves using prices that were calculated as the average price of the first day of the twelve months in the year. This guidance differed from the previous standard of valuing prices according to the end of year prices. The guidance does not require that prior year information be revised for the new method. As a result, this change in methods of pricing should be taken into account while reviewing the comparable information for 2012 and 2011 within this disclosure.

Standardized measure

The Company's proved oil and natural gas reserves for the years ended December 31, 2012 and December 31, 2011 are shown below:

	Years Ended December 31,	
	2012	2011
Natural gas:		
Proved developed and undeveloped reserves (mcf):	-	-
Beginning of year	691,100	714,780
Purchase of natural gas properties in place	-	-
Discoveries and extensions	7,900	-
Revisions	41,992	21,002
Production	(61,582)	(44,682)
Proved reserves, at end of year	679,410	691,100

Oil:	Years Ended December 31, 2012	2011
Proved developed and undeveloped reserves (bbl):	-	-
Beginning of year	8,040	-
Purchase (sale) of oil producing wells in place	(480)	7,053
Discoveries and extensions	10,880	-
Revisions	7,509	1,559
Production	(1,659)	(572)
Proved reserves, at end of year	24,290	8,040

	Years Ended December 31, 2012	2011
Future cash inflows	$ 5,167,850	$ 5,198,500
Future costs:		
Production	(1,640,960)	(2,423,560)
Development	(184,280)	(32,890)
Future cash flows	3,342,610	2,742,050
10% annual discount for estimated timing of cash flow	(1,597,290)	(1,384,610)
Standardized measure of discounted cash flow	$ 1,745,320	$ 1,357,440

Using the SEC adjusted guidelines in place for 2012, the gas and oil prices for this analysis were set at the average price received on the "first-day-of-the-month" for 2012, for appropriate differentials. The "benchmark" prices are $94.71 per barrel and $2.76 per MMBTU. The average quarterly product prices for natural gas revenue for 2011 were $5.73/MCF. The average quarterly product price for oil revenue for 2011 ranged from $87.30 to $95.30 per bbl (barrel).

Future income taxes are based on year-end statutory rates, adjusted for tax basis of oil and natural gas properties and availability of applicable tax assets, such as net operating losses. A discount factor of 10% was used to reflect the timing of future net cash flows.

The standardized measure of discounted future net cash flows is not intended to represent the replacement cost or fair market value of the Company's oil and natural gas properties. An estimate of fair value may also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs, and may require a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

Changes in standardized measure

Included within standardized measure are reserves purchased in place. The purchase of reserves in place includes undeveloped reserves which were acquired at minimal value that have been estimated by independent reserve engineers to be recoverable through existing wells utilizing equipment and operating methods available to the Company and that are expected to be developed in the near term based on an approved plan of development contingent on available capital.

Changes in the standardized measure of future net cash flows relating to proved oil and natural gas reserves for the years ended December 31 is summarized below:

	2012	2011
Increase (decrease)		
Sale of gas and oil, net of operating expenses	$ (175,604)	$ 144,444
Purchase of oil and gas properties in place	-	-
Discoveries, extensions and improved recovery, net of future production and development costs	244,134	-
Accretion of discount	319,350	231,916
Net change in sales prices, net of production costs	-	-
Net increase (decrease)	387,880	376,360
Standardized measure of discounted future cash flows:		
Beginning of the year	1,357,440	981,080
Before Income Taxes	1,745,320	1,357,440
Income Taxes	(601,133)	(461,530)
End of the year	$ 1,144,187	$ 895,910

Note 13 – Subsequent Events

Subsequent to December 31, 2012, Aurora has raised capital contributions of $1,739,000 through the end of May 31, 2013. It is anticipated that the majority of these funds will continue to be applied in the development of the Lightnin' Property as well as others. Also, the Company through its partnership in Aurora, has acquired a 320 acre leasehold (25% working interest and 18.75% net revenue interest) contiguous to the leasehold of its Cotter 6#1 well. The McCauley 6#2 well was spud in May and completion work is currently underway.

The following Exhibits A through F present the interim unaudited condensed consolidated financial statements for the interim periods ended March 31, June 30 and September 30 of 2011 and 2012, which have been restated for the correction of several errors. The interim unaudited condensed financial statements, along with additional explanatory notes detail the amounts as originally reported, the restatement adjustments for each restated account, and the restated amounts for all periods.

VICTORY ENERGY CORPORATION AND SUBSIDIARIES
Exhibit “A”
Form 10-Q
As of March 31, 2011 and the Three Months Then Ended
(Unaudited and Restated)

VICTORY ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Restated)

	3/31/2011 (unaudited)				12/31/2010			
	As Originally Reported	Restatement Adjustments		As Restated	As Originally Reported	Restatement Adjustments		As Restated
ASSETS								
Current Assets								
Cash and cash equivalents	$ 187,494	$ -		$ 187,494	$ 111,572	$ -		$ 111,572
Accounts receivable - net	70,567	-		70,567	74,828	-		74,828
Prepaid Expenses	22,745	-		22,745	24,898	-		24,898
Total current assets	280,806	-		280,806	211,298	-		211,298
Fixed Assets								
Furniture and equipment	10,623	-		10,623	2,294	-		2,294
Accumulated depreciation	(2,491)	-		(2,491)	(2,294)	-		(2,294)
Total furniture and fixtures, net	8,132	-		8,132	-	-		-
Producing oil and natural gas properties, net of impairment	1,466,813	114,778	d	1,581,591	1,466,813	114,778	d	1,581,591
Accumulation depletion	(965,089)	-		(965,089)	(953,084)	-		(953,084)
Drilling costs in process	205,539	-		205,539	-	-		-
Option to acquire leases	25,000	-		25,000	25,000	-		25,000
Total oil and gas properties, net	732,263	114,778		847,041	538,729	114,778		653,507
Other Assets - Funds held at court	13,006	-		13,006	13,006	-		13,006
Total Assets	$ 1,034,207	$ 114,778		$ 1,148,985	$ 763,033	$ 114,778		$ 877,811
LIABILITIES AND STOCKHOLDER'S EQUITY								
Current Liabilities								
Accounts payable	$ 388,097	$ -		$ 388,097	$ 342,285	$ -		$ 342,285
Accrued interest	41,994	-		41,994	10,501	-		10,501
Accrued liabilities	100,093	-		100,093	74,088	-		74,088
	-	-		-	50,000	-		50,000

Accrued liabilities - related parties						
Amounts due former officer	-	-	-	-	404,624	404,624
Line of credit - bank	62,067	-	62,067	68,667	-	68,667
Liability for unauthorized preferred stock issued	85,654	-	85,654	85,654	-	85,654
Total current liabilities	677,905	-	677,905	631,195	404,624	1,035,819
Other Liabilities						
Senior secured convertible debenture, net of debt discount	297,424	-	297,424	127,338	-	127,338
Deferred tax liability	489,550	(489,550) f	-	238,000	(238,000) f	-
Asset retirement obligations	27,282	-	27,282	27,282	-	27,282
Total long term liabilities	814,256	(489,550)	324,706	392,620	(238,000)	154,620
Total liabilities	1,492,161	(489,550)	1,002,611	1,023,815	166,624	1,190,439
Stockholder's Equity						
Common stock, $0.001 par value, 47,500,000 shares authorized, 136,719,608 and 136,719,608 issued and outstanding for 2011and 2010, respectively	136,720	-	136,720	136,720	-	136,720
Additional paid-in capital	32,359,395	(9,243,451) a	23,115,944	31,740,090	(9,611,210) a	22,128,880
Accumulated deficit	(32,954,069)	7,762,811 c	(25,191,258)	(32,137,592)	7,368,005 b	(24,769,587)
Total Victory Energy Corporation stockholder's equity (deficit)	(457,954)	(1,480,640)	(1,938,594)	(260,782)	(2,243,205)	(2,503,987)
Non-controlling interest	-	2,084,968	2,084,968	-	2,191,359	2,191,359
Total stockholder's equity (deficit)	(457,954)	604,328	146,374	(260,782)	(51,846)	(312,628)
Total Liabilities and Stockholder's Equity	$ 1,034,207	$ 114,778	$ 1,148,985	$ 763,033	$ 114,778	$ 877,811

a: Partnership contributions and distributions from January 1, 2008 through December 31, 2010 and tax provisions.

b: Cumulative change in equity due to non-controlling interest from January 1, 2008 through December 31, 2010 and PCAOB adjustments.
c: Non-controlling interest associated with net losses through March 31, 2011 and PCAOB adjustments.
d: Adjustment to correct a material misstatement of impairment.
e: Adjustment for liability due to former officer which was not settled as of December 31, 2010.
f: Adjustment for tax provision.

VICTORY ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
For the three months ended March 31,
(Unaudited and Restated)

	2011			2010		
	As Originally Reported	Restatement Adjustments	As Restated	As Originally Reported	Restatement Adjustments	As Restated
Revenues						
Oil and gas sales	$ 108,320	$ (22,534) e	$ 85,786	$ 149,371	$ -	$ 149,371
Total revenues	108,320	(22,534)	85,786	149,371	-	149,371
Operating Expenses:						
Lease operating costs	69,160	(27,661) e	41,499	11,882	-	11,882
Production taxes	-	5,127 e	5,127	-	-	-
Exploration	-	73,132 e	73,132	-	-	-
General and administrative	688,428	(73,132) e	615,296	158,428	-	158,428
Depreciation, depletion and amortization	12,202	-	12,202	24,983	-	24,983
Total operating expenses	769,790	(22,534)	747,256	195,293	-	195,293
Income (Loss) from operations	(661,470)	-	(661,470)	(45,922)	-	(45,922)
Other Income (Expense):						
Gain on settlement with former officer	-	404,624 c	404,624	404,624	(404,624) c	-
Interest expense	(213,112)	-	(213,112)	(8,252)	-	(8,252)
Total other income and expense	(213,112)	404,624	191,512	396,372	(404,624)	(8,252)
NET INCOME (LOSS) BEFORE TAX BENEFIT	(874,582)	404,624	(469,958)	350,450	(404,624)	(54,174)
TAX BENEFIT	58,105	(58,105) d	-	-	-	-
NET INCOME (LOSS)	(816,477)	346,519	(469,958)	350,450	(404,624)	(54,174)
Less: net income (loss) attributable to non-controlling interest	-	106,391 b	106,391	-	(22,760) a	(22,760)
Net income (loss) attributable to Victory Energy Corporation	$ (816,477)	$ 452,910	$ (363,567)	$ 350,450	$ (427,384)	$ (76,934)

Weighted average shares, basic and diluted	2,735,726		2,735,726	2,734,392		2,734,392
Net loss per share, basic and diluted	$ (0.30)		$ (0.13)	$ 0.13		$ (0.03)

a: Non-controlling interest associated with net income for the three months ended March 31, 2010.
b: Non-controlling interest associated with net loss for the three months ended March 31, 2011.
c: Adjustment for liability due to former officer which was settled as of March 24, 2011.
d: Adjustment for tax provision.
e: Reclassification to the original filing (original filing included third party royalties in the Company's revenues and were improperly deducted as operating expenses).

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Victory Energy Corporation and Subsidiary

Notes to the Consolidated Financial Statements
(Unaudited and Restated)

Note 1 – Financial Statement Presentation

Basis of Presentation, Including Restatement

The accompanying consolidated balance sheet as of December 31, 2010, which has been derived from audited consolidated financial statements, and the accompanying interim consolidated financial statements as of March 31, 2011, for the three-month periods ended March 31, 2011 and 2010, have been prepared by management pursuant to the rules and regulations of the Securities and Exchange Commission ("SEC") for interim financial reporting. These interim consolidated financial statements are unaudited and, in the opinion of management, include all adjustments necessary; to correctly present the non-controlling interest representing the third-party investment in Aurora in our consolidated financial statements, certain prior year amounts have been reclassified to conform to current year presentation to an oil and gas impairment loss error; to correct the reporting of a separation agreement with a former CEO (John Fullenkamp) in March 2011; and to correct the income tax provisions for the years ended December 31, 2011 and 2010 in accordance with ASC 740, Accounting for Income Taxes, to present fairly the financial condition, results of operations and cash flows of Victory Energy Corporation and subsidiary (hereinafter collectively referred to as the "Company") as of and for the periods presented in accordance with accounting principles generally accepted in the United States of America ("GAAP"). Operating results for the three-month period ended March 31, 2011 are not necessarily indicative of the results that may be expected for the year ending December 31, 2011 or for any other interim period during such year. Certain information and footnote disclosures normally included in consolidated financial statements prepared in accordance with GAAP have been omitted in accordance with the rules and regulations of the SEC. The accompanying consolidated financial statements should be read in conjunction with the audited consolidated financial statements and notes thereto contained in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2010 filed with the SEC on May 16, 2011.

The Consolidated Balance Sheet has been restated to present the Additional Paid-in-Capital, Accumulated Deficit and Total Equity (Deficit) attributable to the non-controlling interests at March 31, 2011 and December 31, 2010. The originally reported amounts for December 31, 2010 were $31,740,090, ($32,137,592), and ($260,782), respectively. After restatement for the amounts attributable to non-controlling interests and other adjustments of ($9,611,210) for Additional Paid-in-Capital and $7,368,005 for Accumulated Deficit, resulting in a total equity (deficit) attributable to non-controlling interests of $2,191,359, the Company’s Additional Paid-in-Capital, Accumulated Deficit and Total equity (deficit) is $22,128,880, ($24,769,587), and ($2,503,987), respectively, as of December 31, 2010. As of the period ended March 31, 2011, the originally reported amounts for additional paid-in-capital, accumulated deficit and total equity (deficit) were $32,359,395, ($32,954,069) and ($457,954), respectively. After restatement for the amounts attributable to non-controlling interests of ($9,243,451), $7,762,811, and ($1,480,640), respectively, the resulting restated balances for the Company are $23,115,944, ($25,191,258) and ($1,938,594), respectively.

The Consolidated Statement of Operations has been restated to present the Net Income (Loss) attributable to the non-controlling interests for the three months ended at March 31, 2011 and March 31, 2010, respectively. The originally reported amounts for the Company were ($816,477) and $350,450, respectively. After restatement for the Net Income (Loss) attributable to the non-controlling interests and other adjustments of $452,910 and ($427,384), respectively, the Company’s Net Income (Loss) has been restated as ($363,567) and ($76,934), respectively.

The Consolidated Statement of Cash Flow reflects no restated amounts for the three months ended March 31, 2011 and March 31, 2010, as there were no capital contributions or distributions from non-controlling interest during these periods.

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Resulting Restatement Adjustments

As a result of the issues identified in the Audit Committee Review and the confirmation letter from the SEC, the consolidated financial statements were restated to present the shares of equity and shares of income and loss attributable to the Non-Controlling Interests in the Company's Consolidated Financial Statements. Beginning with cumulative equity affected as of December 31, 2010, the audited consolidated financial statements for the year ended December 31, 2011 have been restated, as have the six unaudited quarterly consolidated interim reports for the calendar years 2011 and 2012. The Company's audited consolidated financial statements for the year ended 2012, reported in this filing, present the NCI. Adjustments have also been made pursuant to findings by the Public Company Accounting Oversight Board for 2010 regarding an error in impairment charges and the timing of reporting a gain from settlement with a former officer. Adjustments have also been made for the 2011 and 2010 interim consolidated statements for corrections to corporate tax provisions.

Organization and nature of operations

Victory Energy Corporation (Pink Sheets symbol VYEY), formerly known as Victory Capital Holdings Corporation (the "Company") was organized under the laws of the State of Nevada on January 7, 1982, under the name All Things, Inc. On March 21, 1985 the Corporation's name was changed to New Environmental Technologies Corporation and on April 28, 2003 to Victory Capital Holdings Corporation. The name was changed finally to Victory Energy Corporation on May 3, 2006.

The business of the Company is to acquire, develop, produce and exploit oil and natural gas properties. The Company's major oil and natural gas properties are located in Texas. The Company's executive offices are located in Austin, Texas and its operations offices are located in Austin, Texas.

The Company's initial authorized capital consisted of 100,000,000 shares of $0.001 par value common voting stock and, as of the date of this filing, has authorized capital of 47,500,000 shares of $0.001 par value common stock.

Going Concern

As presented in the consolidated unaudited and restated consolidated financial statements, we had a net loss of $363,567 for the three months ended March 31, 2011. For the most part, this loss is due to the one-time legal, audit, and accountings charges for the preparation and filing of the 2007, 2008, 2009 and 2010 audited consolidated financial statements with the SEC, the legal costs incurred in the final settlement with the former officer of the Company, as well as the non-cash charges associated with the sale of the Company's 10% Senior Secured Convertible Debentures. Losses are expected to continue in the near term. Current liabilities exceeded current assets by $397,099 and the accumulated deficit is $25,191,258 at March 31, 2011. The Company is currently in default on one of its debt obligations and the Company has no future borrowings or funding sources available under existing financing arrangements. Management anticipates that significant additional capital expenditures will be necessary to develop the Company's oil and natural gas properties before significant positive operating cash flows will be achieved.

Management plans to alleviate these conditions by pursuing business partnering arrangements for the acquisition and development of its properties as well as debt and equity funding through private placements. Without outside investment from the sale of equity securities, debt financing or partnering with other oil and natural gas companies, operating activities and overhead expenses will be reduced to a pace that available operating cash flows will support.

The accompanying consolidated financial statements are prepared as if the Company will continue as a going concern. The consolidated financial statements do not contain adjustments, including adjustments to recorded assets and liabilities, which might be necessary if the Company were unable to continue as a going concern.

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VICTORY ENERGY CORPORATION AND SUBSIDIARIES

Exhibit “B”

Form 10-Q

As of June 30, 2011 and the Six Months Then Ended

(Unaudited and Restated)

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VICTORY ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Restated)

	6/30/2011 (unaudited)					12/31/2010				
	As Originally Reported	Restatement Adjustments		As Restated		As Originally Reported	Restatement Adjustments		As Restated	
ASSETS										
Current Assets										
Cash and cash equivalents	$ 467,712	$ -		$ 467,712		$ 111,572	$ -		$ 111,572	
Accounts receivable - net	70,580	-		70,580		74,828	-		74,828	
Prepaid Expenses	15,074	-		15,074		24,898	-		24,898	
Total current assets	553,366	-		553,366		211,298	-		211,298	
Fixed Assets										
Furniture and equipment	10,623	-		10,623		2,294	-		2,294	
Accumulated depreciation	(2,491)	-		(2,491)		(2,294)	-		(2,294)	
Total furniture and fixtures, net	8,132	-		8,132		-	-		-	
Producing oil and natural gas properties, net of impairment	1,774,980	114,778	d	1,889,758		1,466,813	114,778	d	1,581,591	
Accumulation depletion	(983,491)	-		(983,491)		(953,084)	-		(953,084)	
Option to acquire leases	25,000	-		25,000		25,000	-		25,000	
Total oil and gas properties, net	816,489	114,778		931,267		538,729	114,778		653,507	
Other Assets - Funds held at court	13,006	-		13,006		13,006	-		13,006	
Total Assets	$ 1,390,993	$ 114,778		$ 1,505,771		$ 763,033	$ 114,778		$ 877,811	
LIABILITIES AND STOCKHOLDER'S EQUITY										
Current Liabilities										
Accounts payable	$ 307,397	$ -		$ 307,397		$ 342,285	$ -		$ 342,285	
Accrued interest	57,036	-		57,036		10,501	-		10,501	
Accrued liabilities	95,695	-		95,695		74,088	-		74,088	
Accrued liabilities - related parties	-	-		-		50,000	-		50,000	
	-	-		-		-	404,624	e	404,624	

Amounts due former officer						
Line of credit - bank	62,487	-	62,487	68,667	-	68,667
Liability for unauthorized preferred stock issued	32,164	-	32,164	85,654	-	85,654
Total current liabilities	554,779	-	554,779	631,195	404,624	1,035,819
Other Liabilities						
Senior secured convertible debenture, net of debt discount	89,264	-	89,264	127,338	-	127,338
Deferred tax liability	482,124	(482,124) f	-	238,000	(238,000) f	-
Asset retirement obligations	27,282	-	27,282	27,282	-	27,282
Total long term liabilities	598,670	(482,124)	116,546	392,620	(238,000)	154,620
Total liabilities	1,153,449	(482,124)	671,325	1,023,815	166,624	1,190,439
Stockholder's Equity						
Common stock, $0.001 par value, 47,500,000 shares authorized, 136,719,608 and 136,719,608 issued and outstanding for 2011 and 2010, respectively	382,308	-	382,308	136,720	-	136,720
Additional paid-in capital	33,891,976	(8,977,054) a	24,914,922	31,740,090	(9,611,210) a	22,128,880
Accumulated deficit	(34,036,740)	7,531,455 c	(26,505,285)	(32,137,592)	7,368,005 b	(24,769,587)
Total Victory Energy Corporation stockholder's equity (deficit)	237,544	(1,445,599)	(1,208,055)	(260,782)	(2,243,205)	(2,503,987)
Non-controlling interest	-	2,042,501	2,042,501	-	2,191,359	2,191,359
Total stockholder's equity (deficit)	237,544	596,902	834,446	(260,782)	(51,846)	(312,628)
Total Liabilities and Stockholder's Equity	$ 1,390,993	$ 114,778	$ 1,505,771	$ 763,033	$ 114,778	$ 877,811

a: Partnership contributions and distributions from January 1, 2008 through December 31, 2010 and tax provisions.
b: Cumulative change in equity due to non-controlling interest from January 1, 2008 through December 31, 2010 and PCAOB adjustments.
c: Non-controlling interest associated with net losses through June 30, 2011.

d: Adjustment to correct a material misstatement of impairment.
e: Adjustment for liability due to former officer which was not settled as of December 31, 2010.
f: Adjustment for tax provision.

VICTORY ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited and Restated)

For the Three Months Ended						For the Six Months Ended				
6/30/2011			6/30/2010			6/30/2011			6/30/	
As Originally Reported	Restatement Adjustments	As Restated	As Originally Reported	Restatement Adjustments	As Restated	As Originally Reported	Restatement Adjustments	As Restated	As Originally Reported	Restat Adjus
09,830	$(27,957)f	$81,873	$118,928	$-	$118,928	$218,150	$(50,471)f	$167,679	$268,299	$-
09,830	(27,957)	81,873	118,928	-	118,928	218,150	(50,471)	167,679	268,299	-
7,031	(36,529)f	30,502	39,904	-	39,904	136,191	(64,190)f	72,001	51,786	-
	8,572 f	8,572	-	-	-	-	13,699 f	13,699	-	-
	58,451 f	58,451	-	-	-	-	117,923 f	117,923	-	-
73,693	(58,451)f	415,242	186,774	-	186,774	1,162,121	(117,923)f	1,044,198	345,202	-
8,402	-	18,402	24,983	-	24,983	30,604	-	30,604	49,966	-
59,126	(27,957)	531,169	251,661	-	251,661	1,328,916	(50,491)	1,278,425	446,954	-
449,296)	-	(449,296)	(132,733)	-	(132,733)	(1,110,766)	20	(1,110,746)	(178,655)	-
	-	-	-	-	-	-	404,624 d	404,624	404,624	(40
965,303)	-	(965,303)	(10,869)	-	(10,869)	(1,178,415)	-	(1,178,415)	(19,121)	-
965,303)	-	(965,303)	(10,869)	-	(10,869)	(1,178,415)	404,624	(773,791)	385,503	(40
1,414,599)	-	(1,414,599)	(143,602)	-	(143,602)	(2,289,181)	404,644	(1,884,537)	206,848	(40
31,927	(331,927)e	-	-	-	-	390,032	(390,032)e	-	-	-

1,082,672)	(331,927)		(1,414,599)	(143,602)	-		(143,602)	(1,899,149)	14,612		(1,884,537)	206,848		(404
	42,467	a	42,467	-	16,255	a	16,255	-	148,858	b	148,858	-		(6,5
1,082,672)	$(289,460)		$(1,372,132)	$(143,602)	$16,255		$(127,347)	$(1,899,149)	$163,470		$(1,735,679)	$206,848		$(398