

TENGASCO INC
Form 10-K
March 31, 2014

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

REPORT ON FORM 10-K

(Mark one)

Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended December 31, 2013 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 No. 1-15555

TENGASCO, INC.
(name of registrant as specified in its charter)

Delaware	87-0267438
(state or other jurisdiction of Incorporation or organization)	(I.R.S. Employer Identification No.)

123 Center Park Drive, Knoxville, TN 37922
(Address of Principal Executive Offices) (Zip Code)

Registrant's telephone number, including area code: (865) 675-1554.

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

Securities registered pursuant to Section 12(g) of the Act: Common Stock, \$.001 par value per share.

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

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

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

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

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

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

Large Accelerated Filer Accelerated Filer
Non-accelerated Filer Smaller Reporting Company
(Do not check if a Smaller Reporting Company)

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter was approximately \$21 million (June 28, 2013 closing price \$0.52).

The number of shares outstanding of the registrant's \$.001 par value common stock as of the close of business on March 17, 2014 was 60,842,413.

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FORWARD LOOKING STATEMENTS

The information contained in this Report, in certain instances, includes forward-looking statements within the meaning of applicable securities laws. Forward-looking statements include statements regarding the Company's "expectations," "anticipations," "intentions," "beliefs," or "strategies" or any similar word or phrase regarding the future. Forward-looking statements also include statements regarding revenue margins, expenses, and earnings analysis for 2013 and thereafter; oil and gas prices; exploration activities; development expenditures; costs of regulatory compliance; environmental matters; technological developments; future products or product development; the Company's products and distribution development strategies; potential acquisitions or strategic alliances; liquidity and anticipated cash needs and availability; prospects for success of capital raising activities; prospects or the market for or price of the Company's common stock; and control of the Company. All forward-looking statements are based on information available to the Company as of the date hereof, and the Company assumes no obligation to update any such forward-looking statement. The Company's actual results could differ materially from the forward-looking statements. Among the factors that could cause results to differ materially are the factors discussed in "Risk Factors" below in Item 1A of this Report.

Projecting the effects of commodity prices, which in past years have been extremely volatile, on production and timing of development expenditures includes many factors beyond the Company's control. The future estimates of net cash flows from the Company's proved reserves and their present value are based upon various assumptions about future production levels, prices, and costs that may prove to be incorrect over time. Any significant variance from assumptions could result in the actual future net cash flows being materially different from the estimates.

GLOSSARY OF OIL AND GAS TERMS

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

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Bcf. One billion cubic feet of gas.

BOE. One stock tank barrel equivalent of oil, calculated by converting gas volumes to equivalent oil barrels at a ratio of 6 thousand cubic feet of gas to 1 barrel of oil.

BOPD. Barrels of oil per day.

Btu. British thermal unit. One British thermal unit is the amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Developed oil and gas reserves. Developed oil and gas reserves are reserves of any category that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

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Development project. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

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.

Differential. An adjustment to the price of oil or gas from an established spot market price to reflect differences in the quality and/or location of oil or gas.

Economically producible. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities. The terminal point is generally regarded as the outlet valve on the lease or field storage tank.

Estimated ultimate recovery (EUR). Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date,

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.

Farmout. An assignment of an interest in a drilling location and related acreage conditional upon the drilling of a well on that location.

Gas. Natural gas.

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

MBOE. One thousand BOE.

Mcf. One thousand cubic feet of gas.

Mcfd. One thousand cubic feet of gas per day

MMcfe. One million cubic feet of gas equivalent.

MMBOE. One million BOE.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of gas.

NYMEX. New York Mercantile Exchange.

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Oil. Crude oil, condensate and natural gas liquids.

Operator. The individual or company responsible for the exploration and/or production of an oil or gas well or lease.

Play. A geographic area with hydrocarbon potential.

Polymer. The purpose of the polymer gel treatment is to reduce excessive water production and increase oil or gas production from wells that produce from water-drive reservoirs. These wells are typically produced from naturally fractured carbonate reservoirs such as dolomites and limestone in mature fields. Successful treatments are also run in certain types of sandstone reservoirs. Other practical applications of polymer gels include the treatment of waterflood injection wells to correct channeling or change the injection profile, to improve the ability of the injected fluids to sweep the producing wells in the field, making the waterflood much more efficient and allowing the operator to recover more oil in a shorter period of time.

Proved oil and gas reserves. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government 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 estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project, within a reasonable time.

The area of the reservoir considered as proved includes all of the following: (i) the area identified by drilling and limited by fluid contacts, if any; and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil and gas on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establish a lower contact with reasonable certainty.

Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

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Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the twelve-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved reserve additions. The sum of additions to proved reserves from extensions, discoveries, improved recovery, acquisitions and revisions of previous estimates.

Reserves. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Reserve additions. Changes in proved reserves due to revisions of previous estimates, extensions, discoveries, improved recovery and other additions and purchases of reserves in-place.

Reserve life. A measure of the productive life of an oil and gas property or a group of properties, expressed in years.

Royalty interest. An interest in an oil and gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

Standardized measure. The present value, discounted at 10% per year, of estimated future net revenues from the production of proved reserves, computed by applying sales prices used in estimating proved oil and gas reserves to the year-end quantities of those reserves in effect as of the dates of such estimates and held constant throughout the productive life of the reserves and deducting the estimated future costs to be incurred in developing, producing and abandoning the proved reserves (computed based on year-end costs and assuming continuation of existing economic conditions). Future income taxes are calculated by applying the appropriate year-end statutory federal and state income tax rate with consideration of future tax rates already legislated, to pre-tax future net cash flows, net of the tax basis of the properties involved and utilization of available tax carryforwards related to proved oil and gas reserves.

SWD. Salt water disposal well.

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Undeveloped oil and gas reserves. Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Waterflood. A method of secondary recovery in which water is injected into the reservoir formation to displace residual oil. The water from injection wells physically sweeps the displaced oil to adjacent production wells.

Working interest. An interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations.

References herein to the “Company”, “we”, “us” and “our” mean Tengasco, Inc.

PART I

ITEM 1. BUSINESS.

History of the Company

The Company was initially organized in Utah in 1916 under a name later changed to Onasco Companies, Inc. In 1995, the Company changed its name from Onasco Companies, Inc. by merging into Tengasco, Inc., a Tennessee corporation, formed by the Company solely for this purpose. At the Company’s Annual Meeting held on June 11, 2011, the stockholders of the Company approved an Agreement and Plan of Merger previously adopted by the Company’s Board of Directors which provided for the merger of the Company into a wholly-owned subsidiary formed in Delaware for the purpose of changing the Company’s state of incorporation from Tennessee to Delaware. The merger became effective on June 12, 2011 and the Company is now a Delaware corporation.

OVERVIEW

The Company is in the business of exploration for and production of oil and natural gas. The Company’s primary area of oil exploration and production is in Kansas. The Company’s primary area of natural gas production has been the Swan Creek Field in Tennessee. The Company sold all its oil and gas leases and producing assets in Tennessee on August 16, 2013.

The Company’s wholly-owned subsidiary, Tengasco Pipeline Corporation (“TPC”) owned and operated a 65-mile intrastate pipeline which it constructed to transport natural gas from the Company’s Swan Creek Field to customers in Kingsport, Tennessee. The Company sold all its pipeline related assets on August 16, 2013.

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The Company's wholly-owned subsidiary, Manufactured Methane Corporation ("MMC") operates treatment and delivery facilities in Church Hill, Tennessee for the extraction of methane gas from a landfill for eventual sale of natural gas and electricity.

The Company also had a management agreement with Hoactzin Partners, L.P. ("Hoactzin") to manage Hoactzin's oil and gas properties in the Gulf of Mexico offshore Texas and Louisiana (See below, "4. Management Agreement with Hoactzin"). This management agreement expired on December 18, 2012. Peter E. Salas, the Chairman of the Board of Directors of the Company, is the controlling person of Hoactzin. He is also member of and has voting control primarily through Dolphin Offshore Partners, L.P. of over 96% of shares held by SSB Ventures LLC, which is the Company's largest shareholder. In addition, he is the sole shareholder and controlling person of Dolphin Management, Inc., the general partner of Dolphin Offshore Partners, L.P., which is the Company's second largest shareholder.

General

1. The Kansas Properties

The Company's operated properties in Kansas are located in central Kansas and as of December 31, 2013 include 196 producing oil wells, 19 shut-in wells, and 37 active disposal wells (the "Kansas Properties"). The Company's technical management and staff have a great deal of Kansas exploration and production experience. The Company has onsite production management and field personnel working out of the Hays, Kansas office.

The leases for the Kansas Properties provide for a landowner royalty of 12.5%. Some wells are subject to an overriding royalty interest from 0.5% to 9%. The Company maintains a 100% working interest in most of its wells and undrilled acreage in Kansas. The terms for most of the Company's newer leases in Kansas are from three to five years.

During 2013, the Company drilled 6 gross wells of which 4 wells were operated by the Company. The Company has an average working interest of 77% in the 6 wells. All of the 6 wells drilled were completed as producing wells. One of these wells was completed in January 2014, while the remaining wells were completed during 2013.

All of the Company's current reserve value, production, oil and gas revenue, and future development objectives result from the Company's ongoing interest in Kansas. By using 3-D seismic evaluation on the Company's existing locations, the Company has added and will continue to add proven direct offset locations.

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A. Kansas Ten Well Drilling Program

On September 17, 2007, the Company entered into a ten well drilling program with Hoactzin, consisting of three wildcat wells and seven developmental wells to be drilled on the Company's Kansas Properties (the "Program"). Under the terms of the Program, Hoactzin paid the Company \$0.4 million for each producing well and \$0.25 million for each dry hole. The terms of the Program also provided that Hoactzin would receive all the working interest in the producing wells, and would pay an initial fee to the Company of 25% of its working interest revenues net of operating expenses, referred to as a management fee. The fee paid to the Company by Hoactzin would increase to an 85% working interest when net revenues received by Hoactzin reach an agreed payout point of approximately 1.35 times Hoactzin's purchase price (the "Payout Point"). The Payout Point was reached effective with production in February 2014, at which time the management fee for the Program has increased from 25% to 85%.

Nine of the ten wells in the Program were completed as oil producers and during the 4th quarter 2013 had gross production of approximately 32 barrels per day in total.

In 2013, the wells from the Program produced 12.5 MBbl of which 8.2 MBbl were net to Hoactzin after deduction of royalties and the management fee. As of December 31, 2013, net revenues received by Hoactzin from the Program totaled \$5.15 million which left a balance of \$51,000 which was paid when the Payout Point was reached in February 2014.

The reserve information for the parties' respective Ten Well Program interests as of December 31, 2013 is indicated in the table below. Reserve reports are obtained annually and estimates related to those reports are updated upon receipt of the report. These calculations were made using commodity prices based on the twelve month arithmetic average of the first day of the month price for the period January through December 2013 as required by SEC regulations. The table below reflects values realized at a price of \$90.11 per barrel which was used in the December 31, 2013 reserve report. In addition, the table below reflects achievement of the Payout Point and conversion to an 85% interest in February 2014.

Reserve Information for Ten Well Program Interest as of December 31, 2013

	Barrels Attributable to Party's Interest MBbl	Undiscounted Future Cash Flows Attributable to Party's Interest (in thousands)	Present Value of Future Cash Flows Discounted at 10% Attributable to Party's Interest (in thousands)
Tengasco	116.0	\$ 6,526	\$ 2,815
Hoactzin Partners, L.P.	20.5	\$ 1,152	\$ 497

The Hoactzin Partners, L.P. reserves were estimated based on Tengasco reserves as of December 31, 2013.

B. Kansas Production

The Company's gross oil production in Kansas decreased by 75 MBbl from 279 MBbl in 2012 to 204 MBbl in 2013. This decrease was primarily the result of natural declines from higher 2012 production levels that had resulted from drilling and polymers performed during 2011 and the first half of 2012. Approximately 3 MBbl of the 204 MBbl in 2013 were related to production from the 6 new wells drilled during 2013. Production from 2 of the wells did not commence until after December 31, 2013.

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The capital projects undertaken by the Company in 2013 were initially funded by borrowings from the Company's credit facility. However, these additional borrowings under the Company's credit facility were repaid by December 31, 2013 through use of the Company's operating cash flows.

2. The Tennessee Properties

In the early 1980's Amoco Production Company owned numerous acres of oil and gas leases in the Eastern Overthrust in the Appalachian Basin, including the area now referred to as the Swan Creek Field. In the mid-1980's, however, development of this field was cost prohibitive due to a decline in worldwide oil and gas prices and the high cost of constructing a pipeline to deliver gas to the closest market. In July 1995, the Company acquired the Swan Creek leases and began development of the field. In 2001, the Company completed construction of a 65 mile pipeline from the Swan Creek Field to several meter stations in Kingsport, Tennessee.

The Company has evaluated in recent years whether continued development would add additional reserves and the likelihood of realizing additional revenues from transportation of third party gas through the Company's pipeline assets. The Company determined that current wells would be able to produce the remaining oil and gas reserves and that the Company was unable to attract any additional third party gas without substantial capital investment. As a result, the Company elected to sell its Swan Creek oil and gas assets and its pipeline assets and focus on its oil production from its Kansas Properties.

On March 1, 2013, the Company entered into an agreement with Swan Creek Partners LLC to sell all of the Company's oil and gas leases and producing assets in Tennessee as well as the Company's pipeline assets for \$1.5 million. The Company closed this sale on August 16, 2013.

The carrying value of the pipeline had been classified in assets held for sale in the Balance Sheet and the associated revenues and expenses net of taxes had been classified as discontinued operations in the Statements of Operations. The carrying value of the pipeline included in the Balance Sheet as Assets held for sale was approximately \$1.4 million at December 31, 2012. Since the pipeline asset was sold in August 2013, no amount was recorded in the Balance Sheet as Assets held for sale at December 31, 2013.

As the Swan Creek oil and gas assets represented only a small portion of the Company's full cost pool, these assets remained in oil and gas properties and the gain or loss on the sale was recorded against the full cost pool. Until these properties were sold in August 2013, the related operations were classified in continuing operations.

During 2013, prior to the closing of the sale of the Tennessee oil and gas assets, the Company had 14 producing gas wells and 6 producing oil wells in the Swan Creek Field. Gross gas production volumes from the Swan Creek Field during 2013 until the sale of the properties averaged approximately 226 Mcfd compared to 216 Mcfd produced during year ended December 31, 2012. Gross oil sales volumes from the Swan Creek field during 2013 until the sale of the properties averaged approximately 16.7BOPD compared to approximately 13.4 BOPD produced during the year ended December 31, 2012.

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3. Methane Project

On October 24, 2006, the Company signed a twenty-year Landfill Gas Sale and Purchase Agreement (the “Agreement”) with predecessors in interest of Republic Services, Inc. (“Republic”). The Company assigned its interest in the Agreement to MMC and provides that MMC will purchase the entire naturally produced gas stream being collected at the Carter Valley municipal solid waste landfill owned and operated by Republic in Church Hill, Tennessee and located about two miles from the Company’s pipeline. The Company’s pipeline was sold on August 16, 2013. The Company installed a proprietary combination of advanced gas treatment technology to extract the methane component of the purchased gas stream. The Company constructed a pipeline to deliver the extracted methane gas to the Company’s then existing pipeline (the “Methane Project”).

The total cost for the Methane Project, including pipeline construction, was approximately \$4.5 million. MMC declared startup of commercial operations of the Methane Project on April 1, 2009.

On August 27, 2009, the Company entered into a five-year fixed price gas sales contract with Atmos Energy Marketing, LLC, (“AEM”) in Houston, Texas, a nonregulated unit of Atmos Energy Corporation (NYSE: ATO) for the sale of the methane component of landfill gas produced by MMC at the Carter Valley Landfill. The agreement provides for the sale of up to 600 MMBtu per day. The contract was effective beginning with September 2009 gas production and ends July 31, 2014. The agreed contract price of over \$6 per MMBtu was a premium to the then current five-year strip price for natural gas on the NYMEX futures market.

In April 2011, MMC purchased a Caterpillar genset from Parkway Services Group of Lafayette, Louisiana which was delivered in late 2011 and installed at the plant site for generation of electricity. Total cost of the generator including installation and interconnection with the power grid was approximately \$1.1 million.

On January 25, 2012, MMC commenced sales of electricity generated at the Carter Valley site. The electricity generated is sold under a ten year firm price contract with Holston Electric Cooperative, Inc., the local distributor, and Tennessee Valley Authority through TVA’s Generation Partners program. That program accepted generated renewable power up to 999KW; MMC’s generation equipment is rated at 974 KW to maximize revenues under the favorable electricity pricing under the Generation Partners program. The price provision under this contract pays MMC the current retail price charged monthly to small commercial customers by Holston Electric Cooperative, plus a “green” premium of 3 cents per kilowatt hour (KWH). Current price paid to MMC is approximately \$.129 per KWH. In December 2013, the contract was extended by agreement between the Company, Holston Electric Cooperative, and TVA for an additional ten years beginning in January 2022 at the current price rate less the three-cent “green” premium. A one-eighth royalty on electricity revenues will be paid to the landfill owner.

During 2013, the Methane Project was online approximately 29% of the time resulting in gas sales net revenues net of royalty of \$117,000 compared to being online 59% of the time resulting in gas sales net revenues net of royalty of \$219,000 during 2012. During 2013, the electric generation was online approximately 27% of the time resulting in electric sales net revenues of \$263,000 compared to being online 46% of the time resulting in electric sales net revenues of \$447,000 during 2012. The increase in downtime during 2013 was primarily a result of consistent high levels of oxygen included in the gas coming from the landfill, causing the equipment to shut down until lower oxygen levels on a consistent basis were achieved. As result of this significant down time, the Company reconfigured the fuel supply, added some additional electric generation related equipment, and began an electric generation only program at the Carter Valley site.

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On September 17, 2007, Hoactzin, simultaneously with subscribing to participate in the Ten Well Program (the “Program”), pursuant to a separate agreement with the Company was conveyed a 75% net profits interest in the Methane Project. Because the Payout Point was reached in February 2014 as described above, Hoactzin’s net profits interest in the Methane Project has decreased to 7.5%. The agreed method of calculation of net profits takes into account specific costs and expenses as well as gross gas revenues for the project. As a result of the startup costs, ongoing operating expenses, and reduced production levels discussed above, no net profits as defined have been realized during the period from the project startup in April, 2009 through December 31, 2013 for payment to Hoactzin under the net profits interest. As of the date of this Report, all payments applied to reaching the Payout Point have been generated from the Program.

4. Management Agreement with Hoactzin

On December 18, 2007, the Company entered into a Management Agreement with Hoactzin to manage on behalf of Hoactzin all of its working interest in certain oil and gas properties owned by Hoactzin and located in the onshore Texas Gulf Coast, and offshore Texas and offshore Louisiana. As part of the consideration for the Company’s agreement to enter into the Management Agreement, Hoactzin granted to the Company an option to participate in up to a 15% working interest on a dollar for dollar cost basis in any new drilling or workover activities undertaken on Hoactzin’s managed properties during the term of the Management Agreement. The Management Agreement expired on December 18, 2012. The Company has entered into a transition agreement with Hoactzin whereby the Company will no longer perform operations, but will administratively assist Hoactzin in becoming operator of record of these wells and administratively assist Hoactzin in the transfer of the corresponding bonds from the Company to Hoactzin. This assistance is primarily related to signing the necessary documents to effectuate this transition. Hoactzin and its controlling member are indemnifying the Company for any costs or liabilities incurred by the Company resulting from such assistance, or the fact that the Company is still the operator of record on certain of these wells. As of the date of this Report, the Company continues to administratively assist Hoactzin with this transition process. The transition was anticipated to be completed by this time, and the transition agreement provides that the Company may hold Hoactzin’s drilling programs funds in suspense until the transition process has been completed. As a result, at the time of this Report, the Company is currently holding approximately \$477,000 of such funds pending completion of the transition process.

During the course of the Management Agreement, the Company became the operator of certain properties owned by Hoactzin. The Company obtained from IndemCo, over time, bonds in the face amount of approximately \$10.7 million for the purpose of covering plugging and abandonment obligations for Hoactzin’s operated properties located in federal offshore waters in favor of the Bureau of Ocean Energy Management (“BOEM”), as well as certain private parties. In connection with the issuance of these bonds the Company signed a Payment and Indemnity Agreement with IndemCo whereby the Company guaranteed payment of any bonding liabilities incurred by IndemCo. Dolphin Direct Equity Partners, LP also signed the Payment and Indemnity Agreement, thereby becoming jointly and severally liable with the Company for the obligations to IndemCo. Hoactzin has provided \$6.6 million in cash to IndemCo as collateral for these potential obligations. Dolphin Direct Equity Partners is a private equity fund controlled by Peter E. Salas that has a significant economic interest in Hoactzin. During 2012 and 2013, approximately \$4.6 million of the bonds in the original amount of \$10.7 million were terminated which leaves a balance on the remaining IndemCo bonds of approximately \$6.1 million at December 31, 2013, an amount less than the \$6.6 million in existing collateral supplied by parties other than the Company. Hoactzin has filed the necessary paperwork with the appropriate parties and is awaiting release of the remainder of the IndemCo bonds. The Company anticipates the regulatory process being followed by Hoactzin to be approved in the near future and that these bonds will be released as to the Company and replaced by bonds solely in Hoactzin’s name, at which time operatorship can be placed by the regulatory authority into Hoactzin’s name and the Company’s involvement terminated.

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As part of the transition process, Hoactzin has secured new bonds from Argonaut Insurance Company to replace the IndemCo bonds. Also as part of the transition process, right-of-use and easement (“RUE”) bonds in the amount of \$1.55 million were issued by Argonaut in the Company’s name. Hoactzin is in the process of transferring these RUE bonds from the Company to Hoactzin. Hoactzin and Dolphin Direct signed an indemnity agreement with Argonaut as well as provided full collateral for the new Argonaut bonds, including the RUE bonds issued in the Company’s name. The Company is not party to the indemnity agreement with Argonaut and has not provided any collateral for the bonds issued. As the full cash collateral has been provided by Hoactzin and Dolphin Direct, and Hoactzin is performing the necessary operations and filings need to complete the transfer of the RUE bonds solely to Hoactzin, the Company anticipates the regulatory process to be completed in the near future and these RUE bonds will be released as to the Company.

As designated operator, the Company had routinely contracted in its name for goods and services with vendors. In practice, Hoactzin paid these invoices for goods and services directly to the provider. During late 2009 and early 2010, Hoactzin undertook several significant operations, for which the Company contracted in the ordinary course. As a result of the operations performed in late 2009 and early 2010, Hoactzin currently has significant past due balances to several vendors, a portion of which were included on the Company’s balance sheet. Payables related to these past due and ongoing operations remained outstanding at December 31, 2013 and 2012 in the amount of \$327,000 and \$325,000, respectively. The Company has recorded the Hoactzin-related payables and the corresponding receivable from Hoactzin as of December 31, 2013 and 2012 in its Consolidated Balance Sheets under “Accounts payable – other” and “Accounts receivable – related party”. In addition, as Hoactzin had not made payments since early 2012 to reduce the past due balances from 2009 and from 2010, the Company elected to establish an allowance in the amount of \$159,000 and \$257,000 for the obligations as of December 31, 2013 and 2012, respectively.

The Company, as designated operator, was administratively issued an “Incidence of Non-Compliance” by BOEM concerning one of the Hoactzin wells operated by the Company pursuant to the Management Agreement. This action calls for payment of a civil penalty of \$386,000 for the late filing of certain reports in 2011 by a contractor on the facility. The work to be reported had been timely performed, but the reports were not filed by the contractor. The contractor has since filed for bankruptcy. The Company was not at fault in this matter but is made administratively liable due to the status as designated operator of the well. The Company has filed an appeal of this action in order to attempt to significantly reduce the civil penalty. This appeal required a fully collateralized appeal bond to stay payment of the obligation until the appeal is determined. On November 1, 2012, the Company posted and collateralized this bond with RLI Insurance Company. If the bond was not posted, the appeal would be administratively denied and the order to the Company as operator to pay the \$386,000 penalty would be final. While the Company believes it will ultimately prevail in the appeal process, it is reasonably possible to expect that the Company may be required to pay a portion of this penalty. The Company estimates the range of this possible payment to be between zero and \$386,000.

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No funds have been advanced by the Company to pay any obligations of Hoactzin. No borrowing capability of the Company has been used by the Company in connection with its obligations under the Management Agreement, except for those funds used to collateralize the appeal bond with RLI Insurance Company.

5. Other Areas of Development

Although focused on development of its current Kansas holdings, the Company will continue to review potential transactions involving producing properties and undeveloped acreage in Kansas and the surrounding states.

Governmental Regulations

The Company is subject to numerous state and federal regulations, environmental and otherwise, that may have a substantial negative effect on its ability to operate at a profit. For a discussion of the risks involved as a result of such regulations, see, "Effect of Existing or Probable Governmental Regulations on Business and Costs and Effects of Compliance with Environmental Laws" hereinafter in this section.

Principal Products or Services and Markets

The principal markets for the Company's crude oil are local refining companies. At present, crude oil produced by the Company in Kansas is sold at or near the wells to Coffeyville Resources Refining and Marketing, LLC ("Coffeyville Refining") in Kansas City, Kansas and to National Cooperative Refinery Association ("NCRA") in McPherson, Kansas. Both Coffeyville Refining and NCRA are solely responsible for transportation to their refineries of the oil they purchase. The Company may sell some or all of its production to one or more additional refineries in order to maximize revenues as purchases prices offered by the refineries fluctuate from time to time.

Gas from the Company's Methane Facility is sold at the tailgate of the plant to Atmos Energy Marketing. The contract with Atmos expires in July 2014. Electricity generated at the site is sold to Holston Electric Cooperative. The contract with Holston Electric had a ten year initial commitment and has been extended for an additional ten years as described above. The contract will expire in January 2032.

Drilling Equipment

The Company does not currently own a drilling rig or any related drilling equipment. The Company obtains drilling services as required from time to time from various drilling contractors in Kansas.

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Distribution Methods of Products or Services

Crude oil is normally delivered to refineries in Kansas by tank truck. Natural gas sold from the Company's Methane Facility is distributed and transported by pipeline. Electricity generated at the Company's Methane Facility is distributed into the electric grid.

Competitive Business Conditions, Competitive Position in the Industry and Methods of Competition

The Company's contemplated oil and gas exploration activities in the State of Kansas will be undertaken in a highly competitive and speculative business atmosphere. In seeking any other suitable oil and gas properties for acquisition, the Company will be competing with a number of other companies, including large oil and gas companies and other independent operators with greater financial resources. Management does not believe that the Company's competitive position in the oil and gas industry will be significant as the Company currently exists.

There are numerous producers in the area of the Kansas Properties. Some of these companies are larger than the Company and have greater financial resources. These companies are in competition with the Company for lease positions in the known producing areas in which the Company currently operates, as well as other potential areas of interest.

Although management does not foresee any difficulties in procuring contracted drilling rigs, several factors, including increased competition in the area, may limit the availability of drilling rigs, rig operators and related personnel and/or equipment in the future. Such limitations would have a natural adverse impact on the profitability of the Company's operations.

The Company anticipates no difficulty in procuring well drilling permits in any state. The Company generally does not apply for a permit until it is actually ready to commence drilling operations.

The prices of the Company's products are controlled by the world oil market and the United States natural gas market. Thus, competitive pricing behaviors are considered unlikely; however, competition in the oil and gas exploration industry exists in the form of competition to acquire the most promising acreage blocks and obtaining the most favorable process for transporting the product.

Sources and Availability of Raw Materials

Excluding the development of oil and gas reserves and the production of oil and gas, the Company's operations are not dependent on the acquisition of any raw materials.

Dependence on One or a Few Major Customers

At present, crude oil from the Kansas Properties is being purchased at the well and trucked by Coffeyville Refining and NCRA, which are responsible for transportation of the crude oil purchased. The Company may sell some or all of its production to one or more additional refineries in order to maximize revenues as purchase prices offered by the refineries fluctuate from time to time.

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The Company is presently dependent upon a small number of customers for the sale of gas from the Methane Project. These customers are principally gas marketing companies, utility districts, and industrial customers in the Kingsport area with which the Company may enter into gas sales contracts.

Patents, Trademarks, Licenses, Franchises, Concessions, Royalty Agreements or Labor Contracts, Including Duration

On October 19, 2010, the Company's subsidiary MMC was granted United States Patent No. 7,815,713 for Landfill Gas Purification Method and System, pursuant to application filed January 10, 2007. The patent term is for twenty years from filing date plus adjustment period of 595 days due to the length of the review process resulting in grant of the patent. The patent is for the process designed and utilized by MMC at the Carter Valley landfill facility. The patent may result in a competitive advantage to MMC in seeking new projects, and in the receipt of licensing fees for other projects that may be using or wish to use the process in the future. However, the limited number of high Btu projects currently existing and operated by others, the variety of processes available for use in high Btu projects, and the effects of current gas markets and decreasing or inapplicable green energy incentives for such projects in combination cause the materiality of any licensing opportunity presented by the patent to be difficult to determine or estimate, and thus the licensing fees from the patent, if any are received, may not be material to the Company's overall results of operations.

Need For Governmental Approval of Principal Products or Services

None of the principal products offered by the Company require governmental approval, although permits are required for drilling oil or gas wells.

Effect of Existing or Probable Governmental Regulations on Business

Exploration and production activities relating to oil and gas leases are subject to numerous environmental laws, rules and regulations. The Federal Clean Water Act requires the Company to construct a fresh water containment barrier between the surface of each drilling site and the underlying water table. This involves the insertion of steel casing into each well, with cement on the outside of the casing. The Company has fully complied with this environmental regulation, the cost of which is approximately \$10,000 per well.

As part of the Company's purchase of the Kansas Properties, the Company acquired a statewide permit to drill in Kansas. Applications under such permit are applied for and issued within one to two weeks prior to drilling. At the present time, the State of Kansas does not require the posting of a bond either for permitting or to insure that the Company's wells are properly plugged when abandoned. All of the wells in the Kansas Properties have all permits required and the Company believes that it is in compliance with the laws of the State of Kansas.

The Company's exploration, production and marketing operations are regulated extensively at the federal, state and local levels. The Company has made and will continue to make expenditures in its efforts to comply with the requirements of environmental and other regulations. Further, the oil and gas regulatory environment could change in ways that might substantially increase these costs. These regulations affect the Company's operations and limit the quantity of hydrocarbons it may produce and sell. Other regulated matters include marketing, pricing, transportation and valuation of royalty payments. The Company's operations are also subject to numerous and frequently changing laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. The Company owns or leases, and has in the past owned or leased, properties that have been used for the exploration and production of oil and gas and these properties and the wastes disposed on these properties may be subject to the Comprehensive Environmental Response, Compensation and Liability Act, the Oil Pollution Act of 1990, the Resource Conservation and Recovery Act, the Federal Water Pollution Control Act and analogous state laws. Under such laws, the Company could be required to remove or remediate previously released wastes or property contamination.

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Laws and regulations protecting the environment have generally become more stringent and, may in some cases, impose “strict liability” for environmental damage. Strict liability means that the Company may be held liable for damage without regard to whether it was negligent or otherwise at fault. Environmental laws and regulations may expose the Company to liability for the conduct of or conditions caused by others or for acts that were in compliance with all applicable laws at the time they were performed. Failure to comply with these laws and regulations may result in the imposition of administrative, civil and criminal penalties.

While management believes that the Company’s operations are in substantial compliance with existing requirements of governmental bodies, the Company’s ability to conduct continued operations is subject to satisfying applicable regulatory and permitting controls. The Company’s current permits and authorizations and ability to get future permits and authorizations may be susceptible, on a going forward basis, to increased scrutiny, greater complexity resulting in increased costs or delays in receiving appropriate authorizations.

The Company maintains an Environmental Response Policy and Emergency Action Response Policy Program. A plan was adopted which provides for the erection of signs at each well and at strategic locations along the pipeline containing telephone numbers of the Company’s office. A list is maintained at the Company’s office and at the home of key personnel listing phone numbers for fire, police, emergency services and Company employees who will be needed to deal with emergencies.

The foregoing is only a brief summary of some of the existing environmental laws, rules and regulations to which the Company’s business operations are subject, and there are many others, the effects of which could have an adverse impact on the Company. Future legislation in this area will no doubt be enacted and revisions will be made in current laws. No assurance can be given as to the affect these present and future laws, rules and regulations will have on the Company’s current and future operations.

Research and Development

None.

Number of Total Employees and Number of Full-Time Employees

The Company presently has 18 full time employees and no part-time employees. These employees are located in Colorado, Kansas, and Tennessee.

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Available Information

The Company is a reporting company, as that term is defined under the Securities Acts, and therefore files reports, including Quarterly Reports on Form 10-Q and Annual Reports on Form 10-K such as this Report, proxy information statements and other materials with the Securities and Exchange Commission (“SEC”). You may read and copy any materials the Company files with the SEC at the SEC’s Public Reference Room at 100 F Street, NE, Washington D.C. 20549 upon payment of the prescribed fees. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330.

In addition, the Company is an electronic filer and files its Reports and information with the SEC through the SEC’s Electronic Data Gathering, Analysis and Retrieval system (“EDGAR”). The SEC maintains a website that contains reports, proxy and information statements and other information regarding issuers that file electronically through EDGAR with the SEC, including all of the Company’s filings with the SEC. These may be read and printed without charge from the SEC’s website. The address of that site is www.sec.gov.

The Company’s website is located at www.tengasco.com. On the home page of the website, you may access, free of charge, the Company’s Annual Report on Form 10-K. Under the Investor Information /SEC filings tab you will find the Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, Section 16 filings (Form 3, 4 and 5) and any amendments to those reports as reasonably practicable after the Company electronically files such reports with the SEC. The information contained on the Company’s website is not part of this Report or any other report filed with the SEC.

ITEM 1A. RISK FACTORS

In addition to the other information included in this Form 10-K, the following risk factors should be considered in evaluating the Company’s business and future prospects. The risk factors described below are not exhaustive and you are encouraged to perform your own investigation with respect to the Company and its business. You should also read the other information included in this Form 10-K, including the financial statements and related notes.

The Company’s indebtedness, global recessions, or disruption in the domestic and global financial markets could have an adverse effect on the Company’s operating results and financial condition.

As of December 31, 2013, the outstanding principal amount of the Company’s indebtedness under its credit facility with F&M Bank & Trust Company (“F&M Bank”) was approximately \$3.3 million. The level of indebtedness, coupled with domestic and global economic conditions, the associated volatility of energy prices, and the levels of disruption and continuing relative illiquidity in the credit markets may, if continued for an extended period, have several important and adverse consequences on the Company’s business and operations. For example, any one or more of these factors could (i) make it difficult for the Company to service or refinance its existing indebtedness; (ii) increase the Company’s vulnerability to additional adverse changes in economic and industry conditions; (iii) require the Company to dedicate a substantial portion or all of its cash flow from operations and proceeds of any debt or equity issuances or asset sales to pay or provide for its indebtedness; (iv) limit the Company’s ability to respond to changes in our businesses and the markets in which we operate; (v) place the Company at a disadvantage to our competitors that are not as highly leveraged; or (vi) limit the Company’s ability to borrow money or raise equity to fund our working capital, capital expenditures, acquisitions, debt service requirements, investments, general corporate activity or other financing needs. The Company continues to closely monitor the disruption in the global financial and credit markets, as well as the significant volatility in the market prices for oil and natural gas. As these events unfold, the Company will continue to evaluate and respond to any impact on Company operations. The Company has and will continue to adjust its drilling plans and capital expenditures as necessary. However, external financing in the capital markets may not be readily available, and without adequate capital resources, the Company’s drilling and other activities may be limited and the Company’s business, financial condition and results of operations may suffer. Additionally, in light of

the credit markets and the volatility in pricing for oil and natural gas, the Company's ability to enter into future beneficial relationships with third parties for exploration and production activities may be limited, and as a result, may have an adverse effect on current operational strategy and related business initiatives.

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Agreements Governing the Company's Indebtedness may Limit the Company's Ability to Execute Capital Spending or to Respond to Other Initiatives or Opportunities as they May Arise.

Because the availability of borrowings by the Company under the terms of the Company's amended and restated credit facility with F&M Bank is subject to an upper limit of the borrowing base as determined by the lender's calculated estimated future cash flows from the Company's oil and natural gas reserves, the Company expects any sharp decline in the pricing for these commodities, if continued for any extended period, would very likely result in a reduction in the Company's borrowing base. A reduction in the Company's borrowing base could be significant and as a result, would not only reduce the capital available to the Company but may also require repayment of principal to the lender under the terms of the facility. Additionally, the terms of the Company's amended and restated credit facility with F&M Bank restrict the Company's ability to incur additional debt. The credit facility contains covenants and other restrictions customary for oil and gas borrowing base credit facilities, including limitations on debt, liens, and dividends, voluntary redemptions of debt, investments, and asset sales. In addition, the credit facility requires that the Company maintain compliance with certain financial tests and financial covenants. If future debt financing is not available to the Company when required as a result of limited access to the credit markets or otherwise, or is not available on acceptable terms, the Company may be unable to invest needed capital for drilling and exploration activities, take advantage of business opportunities, respond to competitive pressures or refinance maturing debt. In addition, the Company may be forced to sell some of the Company's assets on an untimely basis or under unfavorable terms. Any of these results could have a material adverse effect on the Company's operating results and financial conditions.

The Company's Borrowing Base under its Credit Facility May be Reduced by the Lender.

The borrowing base under the Company's revolving credit facility will be determined from time to time by the lender, consistent with its customary natural gas and crude oil lending practices. Reductions in estimates of the Company's natural gas and crude oil reserves could result in a reduction in the Company's borrowing base, which would reduce the amount of financial resources available under the Company's revolving credit facility to meet its capital requirements. Such a reduction could be the result of lower commodity prices or production, inability to drill or unfavorable drilling results, changes in natural gas and crude oil reserve engineering, the lender's inability to agree to an adequate borrowing base or adverse changes in the lender's practices regarding estimation of reserves. If either cash flow from operations or the Company's borrowing base decreases for any reason, the Company's ability to undertake exploration and development activities could be adversely affected.

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As a result, the Company's ability to replace production may be limited. In addition, if the borrowing base is reduced, it would be required to pay down its borrowings under the revolving credit facility so that outstanding borrowings do not exceed the reduced borrowing base. This requirement could further reduce the cash available to the Company for capital spending and, if the Company did not have sufficient capital to reduce its borrowing level, could cause the Company to default under its revolving credit facility.

The Company's Credit Facility is Subject to Variable Rates of Interest, Which Could Negatively Impact the Company.

Borrowings under the Company's credit facility with F&M Bank are at variable rates of interest and expose the Company to interest rate risk. If interest rates increase, the Company's debt service obligations on the variable rate indebtedness would increase even though the amount borrowed remained the same, and the Company's income and cash flows would decrease. The Company's credit facility agreement contains certain financial covenants based on the Company's performance. If the Company's financial performance results in any of these covenants being violated, F&M Bank may choose to require repayment of the outstanding borrowings sooner than currently required by the agreement.

Declines in Oil or Gas Prices Have and Will Materially Adversely Affect the Company's Revenues.

The Company's financial condition and results of operations depend in large part upon the prices obtainable for the Company's oil and natural gas production and the costs of finding, acquiring, developing and producing reserves. As seen in recent years, prices for oil and natural gas are subject to extreme fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond the Company's control. These factors include worldwide political instability (especially in the Middle East and other oil producing regions), the foreign supply of oil and gas, the price of foreign imports, the level of drilling activity, the level of consumer product demand, government regulations and taxes, the price and availability of alternative fuels, speculating activities in the commodities markets, and the overall economic environment. The Company's operations are substantially adversely impacted as oil prices decline. Lower prices dramatically affect the Company's revenues from its drilling operations. Further, drilling of new wells, development of the Company's leases and acquisitions of new properties are also adversely affected and limited. As a result, the Company's potential revenues from operations as well as the Company's proved reserves may substantially decrease from levels achieved during the period when oil prices were much higher. There can be no assurances as to the future prices of oil or gas. A substantial or extended decline in oil or gas prices would have a material adverse effect on the Company's financial position, results of operations, quantities of oil and gas that may be economically produced, and access to capital. Oil and natural gas prices have historically been and are likely to continue to be volatile.

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This volatility makes it difficult to estimate with precision the value of producing properties in acquisitions and to budget and project the return on exploration and development projects involving the Company's oil and gas properties. In addition, unusually volatile prices often disrupt the market for oil and gas properties, as buyers and sellers have more difficulty agreeing on the purchase price of properties.

Risk in Rates of Oil and Gas Production, Development Expenditures, and Cash Flows May Have a Substantial Impact on the Company's Finances.

Projecting the effects of commodity prices on production, and timing of development expenditures include many factors beyond the Company's control. The future estimates of net cash flows from the Company's proved and other reserves and their present value are based upon various assumptions about future production levels, prices, and costs that may prove to be incorrect over time. Any significant variance from assumptions could result in the actual future net cash flows being materially different from the estimates, which would have a significant impact on the Company's financial position.

The Company has a History of Significant Losses.

During the early stages of the development of its oil and gas business, the Company had a history of significant losses from operations, in particular its development of the Swan Creek Field and the Company's pipeline assets. In addition, the Company has recorded an impairment of its oil and gas properties during 2008 and impairments of its pipeline assets during 2010 and 2012. As of December 31, 2013, the Company has an accumulated deficit of \$22.8 million. The Company recorded net losses of \$2.0 million in 2009, \$1.7 million in 2010, and \$0.1 million in 2012. In the event the Company experiences losses in the future, those losses may curtail the Company's development and operating activities.

The Company's Oil and Gas Operations Involve Substantial Cost and are Subject to Various Economic Risks.

The Company's oil and gas operations are subject to the economic risks typically associated with exploration, development, and production activities, including the necessity of making significant expenditures to locate or acquire new producing properties or to drill exploratory and developmental wells. In conducting exploration and development activities, the presence of unanticipated pressure or irregularities in formations, miscalculations, and accidents may cause the Company's exploration, development, and production activities to be unsuccessful. This could result in a total loss of the Company's investment in such well(s) or property. In addition, the cost of drilling, completing and operating wells is often uncertain.

The Company's Failure to Find or Acquire Additional Reserves Will Result in the Decline of the Company's Reserves Materially From Their Current Levels.

The rate of production from the Company's Kansas oil properties generally declines as reserves are depleted. Except to the extent that the Company either acquires additional properties containing proved reserves, conducts successful exploration and development drilling, or successfully applies new technologies or identifies additional behind-pipe zones or secondary recovery reserves, the Company's properties proved reserves will decline materially as production from these properties continues. The Company's future oil and natural gas production is therefore highly dependent upon the level of success in acquiring or finding additional reserves or other alternative sources of production. Any decline in oil prices and any prolonged period of lower prices will adversely impact the Company's future reserves since the Company is less likely to acquire additional producing properties during such periods. The lower oil prices have a chilling effect on new drilling and development as such activities become far less likely to be profitable. Thus, any acquisition of new properties poses a greater risk to the Company's financial conditions as such acquisitions may be commercially unreasonable.

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In addition, the Company's drilling for oil and natural gas may involve unprofitable efforts not only from dry wells but also from wells that are productive but do not produce sufficient volumes to be commercially profitable after deducting drilling, operating, and other costs. Also, wells that are profitable may not achieve a targeted rate of return. The Company relies on seismic data and other technologies in identifying prospects and in conducting exploration activities. The seismic data and other technologies used do not allow the Company to know conclusively prior to drilling a well whether oil or natural gas is present or may be produced economically.

The ultimate costs of drilling, completing, and operating a well can adversely affect the economics of a project. Further drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including unexpected drilling conditions, title problems, pressure or irregularities in formations, equipment failures, accidents, adverse weather conditions, environmental and other governmental requirements and the cost of, or shortages or delays in the availability of drilling rigs, equipment, and services.

The Company's Reserve Estimates May Be Subject to Other Material Downward Revisions.

The Company's oil and natural gas reserve estimates may be subject to material downward revisions for additional reasons other than the factors mentioned in the previous risk factor entitled "The Company's Failure to Find or Acquire Additional Reserves Will Result in the Decline of the Company's Reserves Materially from their Current Levels." While the future estimates of net cash flows from the Company's proved reserves and their present value are based upon assumptions about future production levels, prices, and costs that may prove to be incorrect over time, those same assumptions, whether or not they prove to be correct, may cause the Company to make drilling or developmental decisions that will result in some or all of the Company's proved reserves to be removed from time to time from the proved reserve categories previously reported by the Company.

This may occur because economic expectations or forecasts, together with the Company's limited resources, may cause the Company to determine that drilling or development of certain of its properties may be delayed or may not foreseeably occur, and as a result of such decisions any category of proved reserves relating to those yet undrilled or undeveloped properties may be removed from the Company's reported proved reserves. Consequently, the Company's proved reserves of oil may be materially revised downward from time to time.

In addition, the Company may elect to sell some or all of its oil or gas reserves in the normal course of the Company's business. Any such sale would result in all categories of those proved oil or gas reserves that were sold no longer being reported by the Company. In August 2013, the Company sold all of its Tennessee producing oil and gas assets resulting in removal of all Tennessee oil and gas reserves from the Company's reported reserves.

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There is Risk That the Company May Be Required to Write Down the Carrying Value of its Natural Gas and Crude Oil Properties.

The Company uses the full cost method to account for its natural gas and crude oil operations. Accordingly, the Company capitalizes the cost to acquire, explore for and develop natural gas and crude oil properties. Under full cost accounting rules, the net capitalized cost of natural gas and crude oil properties and related deferred income tax if any may not exceed a “ceiling limit” which is based upon the present value of estimated future net cash flows from proved reserves, discounted at 10%, plus cost of properties not being amortized and the lower of cost or estimated fair value of unproven properties included in the cost being amortized. If net capitalized cost of natural gas and crude oil properties exceeds the ceiling limit, the Company must charge the amount of the excess, net of any tax effects, to earnings. This charge does not impact cash flow from operating activities, but does reduce the Company’s stockholders’ equity and earnings. The risk that the Company will be required to write-down the carrying value of natural gas and crude oil properties increases when natural gas and crude oil prices are low. In addition, write-downs may occur if the Company experiences substantial downward adjustments to its estimated proved reserves. An expense recorded in a period may not be reversed in a subsequent period even though higher natural gas and crude oil prices may have increased the ceiling applicable to the subsequent period.

There is a Risk That the Company May Be Required to Write Down the Carrying Value of its Methane Facilities.

The Company’s Methane facility asset is subject to review for impairment whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. The carrying amount is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the pipeline or methane facility assets. Should this occur, the assets carrying amount will be reduced to its fair value and the excess over fair value to net of any tax effects, will be charged to earnings. This expense may not be reversed in future periods.

Use of the Company’s Net Operating Loss Carryforwards May Be Limited.

At December 31, 2013, the Company had, subject to the limitations discussed in this risk factor, substantial amounts of net operating loss carryforwards for U.S. federal and state income tax purposes. These loss carryforwards will eventually expire if not utilized. In addition, as to a portion of the U.S. net operating loss carryforwards, the amount of such carryforwards that the Company can use annually is limited under U.S. tax laws. Uncertainties exist as to both the calculation of the appropriate deferred tax assets based upon the existence of these loss carryforwards, as well as the future utilization of the operating loss carryforwards under the criteria set forth under FASB ASC 740, Income Taxes. In addition, limitations exist upon use of these carryforwards in the event of a change in control of the Company occurs. There are risks that the Company may not be able to utilize some or all of the remaining carryforwards, or that deferred tax assets that were previously booked based upon such carryforwards may be written down or reversed based on future economic factors that may be experienced by the Company. The effect of such write downs or reversals, if they occur, may be material and substantially adverse.

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Shortages of Oil Field Equipment, Services or Qualified Personnel Could Adversely Affect the Company's Results of Operations.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers, and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. The Company does not own any drilling rigs and is dependent upon third parties to obtain and provide such equipment as needed for the Company's drilling activities. There have also been shortages of drilling rigs and other equipment when oil prices have risen. As prices increased, the demand for rigs and equipment increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher oil prices in Kansas have currently stimulated and increased demand and this has resulted in increased prices for drilling rigs, crews and associated supplies, equipment and services, as well as increased potential that the Company's experienced employee base in Kansas conducting field operations may be offered employment by competing companies and the Company may not be capable of replacing such departing personnel at existing salary levels, or at all. These shortages or price increases could adversely affect the Company's profit margin, cash flow, and operating results or restrict the Company's ability to drill wells and conduct ordinary operations.

The Company has Significant Costs to Conform to Government Regulation of the Oil and Gas Industry.

The Company's exploration, production, and marketing operations are regulated extensively at the federal, state and local levels. The Company is currently in compliance with these regulations. In order to maintain its compliance, the Company has made and will have to continue to make substantial expenditures in its efforts to comply with the requirements of environmental and other regulations. Further, the oil and gas regulatory environment could change in ways that might substantially increase these costs. Hydrocarbon-producing states regulate conservation practices and the protection of correlative rights. These regulations affect the Company's operations and limit the quantity of hydrocarbons it may produce and sell. Other regulated matters include marketing, pricing, transportation and valuation of royalty payments.

The Company has Significant Costs Related to Environmental Matters.

The Company's operations are also subject to numerous and frequently changing laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. The Company owns or leases, and has owned or leased, properties that have been leased for the exploration and production of oil and gas and these properties and the wastes disposed on these properties may be subject to the Comprehensive Environmental Response, Compensation and Liability Act, the Oil Pollution Act of 1990, the Resource Conservation and Recovery Act, the Federal Water Pollution Control Act and similar state laws. Under such laws, the Company could be required to remove or remediate wastes or property contamination.

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Laws and regulations protecting the environment have generally become more stringent and, may in some cases, impose “strict liability” for environmental damage. Strict liability means that the Company may be held liable for damage without regard to whether it was negligent or otherwise at fault. Environmental laws and regulations may expose the Company to liability for the conduct of or conditions caused by others or for acts that were in compliance with all applicable laws at the time they were performed. Failure to comply with these laws and regulations may result in the imposition of administrative, civil and criminal penalties.

The Company’s ability to conduct continued operations is subject to satisfying applicable regulatory and permitting controls. The Company’s current permits and authorizations and ability to get future permits and authorizations may be susceptible, on a going forward basis, to increased scrutiny, greater complexity resulting in increased cost or delays in receiving appropriate authorizations.

Insurance Does Not Cover All Risks.

Exploration for and development and production of oil can be hazardous, involving unforeseen occurrences such as blowouts, fires and loss of well control, which can result in damage to or destruction of wells or production facilities, injury to persons, loss of life or damage to property or to the environment. Although the Company maintains insurance against certain losses or liabilities arising from its operations in accordance with customary industry practices and in amounts that management believes to be prudent, insurance is not available to the Company against all operational risks.

The Company’s Methane Extraction Operation from Non-conventional Reserves Involve Substantial Costs and is Subject to Various Economic, Operational, and Regulatory Risks.

The Company’s operations in its existing project involving the extraction of methane gas from non-conventional reserves such as landfill gas streams, required investment of substantial capital and is subject to the risks typically associated with capital intensive operations, including risks associated with the availability of financing for required equipment, construction schedules, air and water environmental permitting, and locating transportation facilities and customers for the products produced from those operations which may delay or prevent startup of such projects. After startup of commercial operations, the presence of unanticipated pressures or irregularities in constituents of the raw materials used in such projects from time to time, miscalculations or accidents may cause the Company’s project activities to be unsuccessful. Although the technologies to be utilized in such projects is believed to be effective and economical, there are operational risks in the use of such technologies in the combination to be utilized by the Company as a result of both the combination of technologies and the early stages of commercial development and use of such technologies for methane extraction from non-conventional sources such as those to be used by the Company. This risk could result in total or partial loss of the Company’s investment in such projects. The economic risks of such projects include the marketing risks resulting from price volatility of the methane gas produced from such projects, which is similar to the price volatility of natural gas. This project is also subject to the risk that the products manufactured may not be accepted for transportation in common carrier gas transportation facilities, although the products meet specified requirements for such transportation, or may be accepted on such terms that reduce the returns of such projects to the Company. This project is also subject to the risk that the product manufactured may not be accepted by purchasers thereof from time to time and the viability of such projects would be dependent upon the Company’s ability to locate a replacement market for physical delivery of the gas produced from the project.

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The Company's methane extraction business is the subject of patents granted to the Company. There can be no assurance that our existing patents will not be invalidated, circumvented or challenged, or that we will be issued any patents sought in the future, or that the rights granted or to be granted under any patents will provide us competitive advantages.

We have been granted one U.S. patent and have been granted a continuation patent application relating to certain aspects of our methane extraction technology and we may seek additional patents on future innovations. Our ability to license our technology is substantially dependent on the validity and enforcement of this patent. We cannot assure you that our patent will not be invalidated, circumvented or challenged, that the rights granted under the patents will provide us competitive advantages, or that our current and future patent applications will be granted. In addition, third parties may seek to challenge, invalidate, circumvent or render unenforceable any patents or proprietary rights owned by or licensed to us based on, among other things: subsequently discovered prior art; lack of entitlement to the priority of an earlier, related application; or failure to comply with the written description, best mode, enablement or other applicable requirements. If a third party is successful in challenging the validity of our patent, our inability to enforce our intellectual property rights could materially harm our methane extraction business. Furthermore, our technology may be the subject of claims of intellectual property infringement in the future. Our technology may not be able to withstand third-party claims or rights against their use.

Any intellectual property claims, with or without merit, could be time-consuming, expensive to litigate or settle, could divert resources and attention and could require us to obtain a license to use the intellectual property of third parties. We may be unable to obtain licenses from these third parties on favorable terms, if at all. Even if a license is available, we may have to pay substantial royalties to obtain a license. If we cannot defend such claims or obtain necessary licenses on reasonable terms, we may be precluded from offering most or all of our technology and our methane extraction business may be adversely affected.

The Company Faces Significant Competition with Respect to Acquisitions or Personnel.

The oil and gas business is highly competitive. In seeking any suitable oil and gas properties for acquisition, or drilling rig operators and related personnel and equipment, the Company is a small entity with limited financial resources and may not be able to compete with most other companies, including large oil and gas companies and other independent operators with greater financial and technical resources and longer history and experience in property acquisition and operation.

The Company Depends on Key Personnel, Whom it May Not be Able to Retain or Recruit.

Certain members of present management and certain Company employees have substantial expertise in the areas of endeavor presently conducted and to be engaged in by the Company specifically including engineering and geology. To the extent that their services become unavailable, the Company would be required to retain other and additional qualified personnel to perform these services in technical areas upon which the Company is dependent to conduct exploration and production activities. The Company does not know whether it would be able to recruit and hire qualified and additional persons upon acceptable terms. The Company does not maintain "Key Person" insurance for any of the Company's key employees.

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The Company's Operations are Subject to Changes in the General Economic Conditions.

Virtually all of the Company's operations are subject to the risks and uncertainties of adverse changes in general economic conditions, the outcome of potential legal or regulatory proceedings, changes in environmental, tax, labor and other laws and regulations to which the Company is subject, and the condition of the capital markets utilized by the Company to finance its operations.

Being a Public Company Significantly Increases the Company's Administrative Costs.

The Sarbanes-Oxley Act of 2002, as well as rules subsequently implemented by the SEC and listing requirements subsequently adopted by the NYSE MKT, the exchange on which the Company's stock is traded, in response to Sarbanes-Oxley, have required changes in corporate governance practices, internal control policies and audit committee practices of public companies. Although the Company is a relatively small public company, these rules, regulations, and requirements for the most part apply to the same extent as they apply to all major publicly traded companies. As a result, they have significantly increased the Company's legal, financial, compliance and administrative costs, and have made certain other activities more time consuming and costly, as well as requiring substantial time and attention of our senior management. The Company expects its continued compliance with these and future rules and regulations to continue to require significant resources. These rules and regulations also may make it more difficult and more expensive for the Company to obtain director and officer liability insurance in the future, and could make it more difficult for it to attract and retain qualified members for the Company's Board of Directors, particularly to serve on its audit committee.

The Company's Chairman of the Board Beneficially Controls a Substantial Amount of the Company's Common Stock and Has Significant Influence over the Company's Business.

Peter E. Salas, the Chairman of the Company's Board of Directors, is the sole shareholder and controlling person of Dolphin Management, Inc. the general partner of Dolphin Offshore Partners, L.P. ("Dolphin"), and a member of SSB Ventures LLC ("SSB") which is the Company's largest shareholder. At March 17, 2014, Mr. Salas through Dolphin and SSB controls 21,057,492 shares of the Company's common stock and had options granting him the right to acquire an additional 125,000 shares of common stock. His ownership and voting control of approximately 35% of the Company's common stock gives him significant influence on the outcome of corporate transactions or other matters submitted to the Board of Directors or shareholders for approval, including mergers, consolidations and the sale of all or substantially all of the Company's assets.

Shares Eligible for Future Sale May Depress the Company's Stock Price.

At March 17, 2014, the Company had 60,842,413 shares of common stock outstanding of which 21,326,718 shares were held by officers, directors, and affiliates. In addition, options to purchase 845,250 shares of unissued common stock were granted under the Tengasco, Inc. Stock Incentive Plan of which options to purchase 765,250 shares were vested at March 17, 2014.

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All of the shares of common stock held by affiliates are restricted or controlled securities under Rule 144 promulgated under the Securities Act of 1933, as amended (the "Securities Act"). The shares of the common stock issuable upon exercise of the stock options have been registered under the Securities Act. Sales of shares of common stock under Rule 144 or another exemption under the Securities Act or pursuant to a registration statement could have a material adverse effect on the price of the common stock and could impair the Company's ability to raise additional capital through the sale of equity securities.

Future Issuance of Additional Shares of the Company's Common Stock Could Cause Dilution of Ownership Interest and Adversely Affect Stock Price.

The Company may in the future issue previously authorized and unissued securities, resulting in the dilution of the ownership interest of its current stockholders. The Company is currently authorized to issue a total of 100 million shares of common stock with such rights as determined by the Board of Directors. Of that amount, approximately 61 million shares have been issued. The potential issuance of the approximately 39 million remaining authorized but unissued shares of common stock may create downward pressure on the trading price of the Company's common stock.

The Company may also issue additional shares of its common stock or other securities that are convertible into or exercisable for common stock for raising capital or other business purposes. Future sales of substantial amounts of common stock, or the perception that sales could occur, could have a material adverse effect on the price of the Company's common stock.

The Company May Issue Shares of Preferred Stock with Greater Rights than Common Stock.

Subject to the rules of the NYSE MKT, the Company's charter authorizes the Board of Directors to issue one or more series of preferred stock and set the terms of the preferred stock without seeking any further approval from holders of the Company's common stock. Any preferred stock that is issued may rank ahead of the Company's common stock in terms of dividends, priority and liquidation premiums and may have greater voting rights than the Company's common stock.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES.

Property Location, Facilities, Size and Nature of Ownership.

The Company leases its principal executive offices, consisting of approximately 2,114 square feet located at 123 Center Park Drive, Suite 104, Knoxville, Tennessee at a rental of \$6,000 per month, on a month to month lease. In addition, the Company leases an office for its technical employees, consisting of 1,828 square feet located at 6021 S. Syracuse Way, Suite 305, Greenwood Village, Colorado at a rental of \$2,666 per month, expiring in February 2017. The Company also leases an office in Hays, Kansas at a rental of \$750.00 per month that is currently a month to month lease.

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The Company carries insurance on its Kansas properties, Methane facility, offices, and office contents. As of December 31, 2013, the Company does not have an interest in producing or non-producing oil and gas properties in any state other than Kansas.

Kansas Properties

The Kansas Properties as of December 31, 2013 contained 24,273 gross acres in central Kansas. Of these 24,273 gross acres, 13,751 acres were held by production and 10,522 acres were undeveloped.

Many of these leases are still in effect because they are being held by production. The Kansas leases provide for a landowner royalty of 12.5%. Some wells are subject to an overriding royalty interest from 0.5% to 9%. The Company maintains a 100% working interest in most of its wells and undrilled acreage in Kansas. The terms for most of the Company's newer leases in Kansas are from three to five years.

During 2013, the Company drilled 6 gross wells of which 4 wells are operated by the Company. The other 2 wells are operated by the Company's working interest partners in the wells. The Company has an average working interest of 77% in the 6 wells. All of the 6 wells drilled were completed as producing wells. One of these wells was completed in January 2014, while the remaining wells were completed during 2013.

All of the Company's current reserve value, production, revenue, and future development objectives result from the Company's ongoing interest in Kansas. By using 3-D seismic evaluation on the Company's existing locations, the Company has added and will continue to add proven direct offset locations.

The map below indicates the location of the 10 counties in Kansas in which the Company had production as of December 31, 2013.

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Tennessee Properties

The Company closed the sale of all its Tennessee oil and gas leases on August 16, 2013.

Reserve and Production Summary

The following tables indicate the county breakdown of 2013 production and reserve values as of December 31, 2013. The Hancock County, TN amounts represent production through August 16, 2013 when properties in this county were sold:

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Production by County

Area	Gross Production MBOE	Average Net Revenue Interest	Percentage of Total Oil Production
Rooks County, KS	133.2	0.791604	61.6%
Trego County, KS	33.0	0.805023	15.2%
Ellis County, KS	9.9	0.813621	4.6%
Graham County, KS	7.1	0.869341	3.3%
Barton County, KS	5.9	0.815528	2.7%
Russell County, KS	4.5	0.790989	2.1%
Pawnee County, KS	4.2	0.785728	2.0%
Rush County, KS	2.8	0.868461	1.3%
Osborne County, KS	1.9	0.593716	0.9%
Stafford County, KS	1.4	0.716195	0.6%
Total KS	203.9		94.3%
Hancock County, TN	12.4	0.690415	5.7%
Total	216.3		100.0%

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Reserve Value by County Discounted at 10% (in thousands)

Area	Proved Developed	Proved Undeveloped	Proved Reserves	% of Total
Rooks County, KS	\$ 25,730	\$ 5,077	\$ 30,807	64.4 %
Trego County, KS	6,026	494	6,520	13.6 %
Graham County, KS	1,522	1,891	3,413	7.1 %
Ellis County, KS	2,309	-	2,309	4.8 %
Barton County, KS	1,694	296	1,990	4.1 %
Pawnee County, KS	410	624	1,034	2.2 %
Russell County, KS	699	-	699	1.5 %
Rush County, KS	668	-	668	1.4 %
Stafford County, KS	119	166	285	0.6 %
Osborne County, KS	131	-	131	0.3 %
Total	\$ 39,308	\$ 8,548	\$ 47,856	100.0%

Reserve Analyses

The Company's estimated total net proved reserves of oil and natural gas as of December 31, 2013 and 2012, and the present values of estimated future net revenues attributable to those reserves as of those dates, are presented in the following tables. All of the Company's reserves were located in the United States. These estimates were prepared by LaRoche Petroleum Consultants, Ltd. ("LaRoche") of Dallas, Texas, and are part of their reserve reports on the Company's oil and gas properties. LaRoche and its employees and its registered petroleum engineers have no interest in the Company and performed those services at their standard rates. LaRoche's estimates were based on a review of geologic, economic, ownership, and engineering data provided to them by the Company. In accordance with SEC regulations, no price or cost escalation or reduction was considered. The technical persons at LaRoche responsible for preparing the Company's reserve estimates meet the requirements regarding qualifications, independence,

objectivity, and confidentiality set forth in the standards pertaining to the estimating and auditing of oil and gas reserves information promulgated by the Society of Petroleum Engineers. Our independent third party engineers do not own an interest in any of our properties and are not employed by the Company on a contingent basis.

Total Proved Reserves as of December 31, 2013

	Producing	Non Producing	Undeveloped	Total
Oil (MBbl)	1,465	110	465	2,040
Future net cash flows before income taxes discounted at 10% (in thousands)	\$ 34,440	\$ 4,868	\$ 8,548	\$ 47,856

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Total Proved Reserves as of December 31, 2012

	Producing	Non-producing	Undeveloped	Total
Natural gas (MMcf)	22	-	-	22
Oil (MBbl)	1,743	79	391	2,213
Total proved reserves (MBOE)	1,747	79	391	2,217
Future net cash flows before income taxes discounted at 10% (in thousands)	\$ 42,626	\$ 3,235	\$ 8,050	\$ 53,911

Historically, all drilling has primarily been funded by cash flows from operations with supplemental funding provided by the Company's credit facility. The Company's Proved Undeveloped Reserves at December 31, 2013 included 29 locations as compared to 23 locations at December 31, 2012. The future development cost related to the Company's Proved Undeveloped locations at December 31, 2013 was approximately \$9.6 million. The Company intends to fund the drilling of these locations through operating cash flow and, as needed, supplement the funding by drawing on the Company's credit facility. During 2013, approximately 16.7 MBbl of proved undeveloped reserves that existed at December 31, 2012 were converted into proved developed reserves from drilling and completion. All proved undeveloped reserves included in the Company's report at December 31, 2013 and 2012 are related to oil prospects in Kansas. During 2012, approximately 57 MBbl of proved undeveloped reserves that existed at December 31, 2011 were converted into proved developed reserves.

The oil price after basis adjustments used in our December 31, 2013 reserve valuation was \$90.11 per Bbl. The oil and natural gas prices after basis adjustments used in our December 31, 2012 reserve valuation were \$88.08 per Bbl and \$2.76 per Mcf. The primary factors causing the decrease in proved reserve volumes from December 31, 2012 levels were 2013 reserve additions not being significant enough to offset 2013 production as well as downward revisions of certain producing properties. (Refer to Note 15, Supplemental Oil and Gas Information, Standardized Measure of Discounted Future Net Cash Flows in the Company's Notes to Consolidated Financial Statements for additional reserve information.)

The assumed prices used in calculating the estimated future net revenue attributable to proved reserves do not necessarily reflect actual market prices for oil production sold after December 31, 2013. There can be no assurance that all of the estimated proved reserves will be produced and sold at the assumed prices. Accordingly, the foregoing prices should not be interpreted as a prediction of future prices.

In substance, the LaRoche Report used estimates of oil and gas reserves based upon standard petroleum engineering methods which include production data, decline curve analysis, volumetric calculations, pressure history, analogy, various correlations and technical factors. Information for this purpose was obtained from owners of interests in the areas involved, state regulatory agencies, commercial services, outside operators and files of LaRoche.

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Management has established, and is responsible for, internal controls designed to provide reasonable assurance that the estimates of Proved Reserves are computed and reported in accordance with SEC rules and regulations as well as with established industry practices. The Company's Exploration Manager and Petroleum Engineer each have extensive experience evaluating reserves on a well by well basis and on a company wide basis. Prior to generation of the annual reserves, management and staff meet with LaRoche to review properties and discuss assumptions to be used in the calculation of reserves. Management reviews all information submitted to LaRoche to ensure the accuracy of the data. Management also reviews the final report from LaRoche and discusses any differences from Management expectations with LaRoche.

Production

The following tables summarize for the past three fiscal years the volumes of oil and gas produced from operated properties, the Company's operating costs, and the Company's average sales prices for its oil and gas. The net production volumes excluded volumes produced to royalty interest or other parties' working interest. Tennessee amounts in 2013 represent results through August 16, 2013 when these properties were sold.

Kansas

Years Ended December 31,	Gross Production		Net Production		Cost of Net Production (Per BOE)	Average Sales Price	
	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)		Oil (Bbl)	Gas (Per Mcf)
2013	203.9	-	162.5	-	\$ 28.27	\$91.00	-
2012	278.8	-	225.9	-	\$ 22.48	\$86.90	-
2011	240.8	-	185.7	-	\$ 25.81	\$88.15	-

Tennessee

Years Ended December 31,	Gross Production		Net Production		Cost of Net Production (Per BOE)	Average Sales Price	
	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)		Oil (Bbl)	Gas (Per Mcf)
2013	3.8	51.3	2.7	37.9	\$ 28.90	\$92.66	\$3.94
2012	4.9	78.8	3.5	56.2	\$ 39.08	\$88.29	\$3.35
2011	5.4	52.8	3.8	41.6	\$ 44.13	\$87.33	\$4.28

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Although the 2013 cost per BOE on Kansas production is higher than both 2011 and 2012, total Kansas operating cost in 2013 of \$4.6 million is lower than the 2011 operating cost of \$4.8 million and 2012 operating cost of \$5.1 million.

Oil and Gas Drilling Activities

Kansas

During 2013, the Company participated in drilling 6 wells. Of the 6 wells drilled, the Company operates 4 of the wells while the 2 remaining wells are operated by the Company's working interest partners in those wells. The Company has an average working interest of 77% in the 6 wells. All of the 6 wells drilled were completed as producing wells. One of these wells was completed in January 2014, while the remaining wells were completed during 2013. The successful wells contributed approximately 3 MBbl of gross production during 2013. Production from 2 of the wells did not commence until after December 31, 2013.

Tennessee

In 2013 the Company did not drill any new wells in the Swan Creek Field or any other Company acreage in Tennessee. In August 2013, the Company completed the sale of all its oil and gas producing and non-producing properties in Tennessee.

Gross and Net Wells

The following tables set forth the fiscal years ending December 31, 2013, 2012 and 2011 the number of gross and net development wells drilled by the Company. The term gross wells means the total number of wells in which the Company owns an interest, while the term net wells means the sum of the fractional working interest the Company owns in the gross wells.

	For Years Ending December					
	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Kansas						
Productive Wells	6	5	15	15	16	16
Dry Holes	-	-	5	5	9	9
Salt Water Disposal	-	-	-	-	-	-
Tennessee						
Dry Holes	-	-	-	-	1	1

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Productive Wells

As of December 31, 2013, the Company held a working interest in 218 gross wells and 212 net wells in Kansas. Productive wells are either producing wells or wells capable of commercial production although currently shut-in. One or more completions in the same bore hole are counted as one well. The term gross wells means the total number of wells in which the Company owns an interest, while the term net wells means the sum of the fractional working interests the Company owns in all of the gross wells. Tennessee productive wells were sold in August 2013.

Developed and Undeveloped Oil and Gas Acreage

As of December 31, 2013 the Company owned working interests in the following developed and undeveloped oil and gas acreage. The term gross acres means the total number of acres in which the Company owns an interest, while the term net acres means the sum of the fractional working interest the Company owns in the gross acres, less the interest of royalty owners.

	Developed		Undeveloped		Total	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
Kansas	13,751	11,364	10,522	8,516	24,273	19,880

The following table identifies the number of gross and net undeveloped acres as of December 31, 2013 that will expire, by year, unless production is established before lease expiration or unless the lease is renewed.

	2014	2015	2016	Total
Gross Acres	8,672	1,050	800	10,522
Net Acres	7,019	850	647	8,516

ITEM 3. LEGAL PROCEEDINGS

The Company is not a party to any pending material legal proceeding. To the knowledge of management, no federal, state, or local governmental agency is presently contemplating any proceeding against the Company which would have a result materially adverse to the Company. To the knowledge of management, no director, executive officer or affiliate of the Company or owner of record or beneficially of more than 5% of the Company's common stock is a party adverse to the Company or has a material interest adverse to the Company in any proceeding.

ITEM 4. MINE SAFETY DISCLOSURES.

Not Applicable.

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PART II

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

Market Information

The Company's common stock is listed on the NYSE MKT exchange under the symbol TGC. The range of high and low sales prices for shares of common stock of the Company as reported on the NYSE MKT during the fiscal years ended December 31, 2013 and December 31, 2012 are set forth below.

For the Quarters Ending	High	Low
March 31, 2013	\$0.82	\$0.60
June 30, 2013	\$0.71	\$0.48
September 30, 2013	\$0.58	\$0.35
December 31, 2013	\$0.48	\$0.37
March 31, 2012	\$1.20	\$0.72
June 30, 2012	\$1.10	\$0.68
September 30, 2012	\$0.86	\$0.68
December 31, 2012	\$0.74	\$0.58

Holders

As of March 17, 2014, the number of shareholders of record of the Company's common stock was 277 and management believes that there are approximately 6,700 beneficial owners of the Company's common stock.

Dividends

The Company did not pay any dividends with respect to the Company's common stock in 2013 or 2012 and has no present plans to declare any dividends with respect to its common stock.

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Recent Sales of Unregistered Securities

During the fourth quarter of fiscal 2013, the Company did not sell or issue any unregistered securities. Any unregistered equity securities that were sold or issued by the Company during the first three quarters of fiscal 2013 were previously reported in Reports filed by the Company with the SEC.

Purchases of Equity Securities by the Company and Affiliated Purchasers

Neither the Company nor any of its affiliates repurchased any of the Company's equity securities during 2013.

Equity Compensation Plan Information

See Item 12, "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matter" for information regarding the Company's equity compensation plans.

ITEM 6. SELECTED FINANCIAL DATA

Not Applicable.

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

Results of Operations

The Company reported net income from continuing operations of \$3.0 million or \$0.05 per share in 2013 compared to net income from continuing operations of \$4.2 million or \$0.07 per share in 2012 and net income from continuing operations of \$5.0 million or \$0.08 per share in 2011. The Company reported a net loss from discontinued operations of \$(0.14) million or \$(0.00) per share in 2013 compared to a net loss from discontinued operations of \$(4.3) million or \$(0.07) per share in 2012 and a net loss from discontinued operations of \$(0.29) million or \$(0.00) per share in 2011. The net loss from discontinued operations in 2012 was primarily due to impairments of the Company's pipeline assets in the amounts of approximately \$3.4 million. Discontinued operations are net of associated taxes.

The Company realized revenues of approximately \$15.7 million in 2013 compared to \$20.6 million in 2012 and \$17.1 million in 2011. During 2013, revenues decreased approximately \$(4.9) million of which \$(5.2) million was related to decreases in oil sales volumes from 226.6 MBbl in 2012 to 166.2 MBbl in 2013. The more significant production declines were experienced in the Albers, Coddington, Hilgers B, Liebenau, McElhaney A, Veverka A, and Zerger A leases. These decreases were primarily due to higher 2012 production as a result of drilling and polymers on these leases during 2011 and the first half of 2012. In addition there was also a \$(0.3) million decrease in sales from the Methane Project and electric generation at the landfill related to increased downtime as a result of consistent high levels of oxygen in the landfill gas during 2013 which caused equipment to shut down until lower oxygen levels on a consistent basis were achieved. These decreases were partially offset by a \$0.7 million increase related to a \$4.11 per barrel increase in the average oil price received from \$86.92 per barrel received in 2012 to \$91.03 per barrel received in 2013. During 2012, revenues increased \$3.5 million of which \$3.3 million related to increases in oil sales volumes from 189.5 MBbl in 2011 to 226.6 MBbl in 2012. In addition, Methane Project revenues increased \$0.5 million in 2012 primarily from electricity sales which commenced in January 2012. These increases were partially offset by a \$(0.3) million decrease related to a \$(1.21) per barrel decrease in the average oil price received from \$88.13 per barrel in 2011 to \$86.92 per barrel received in 2012.

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Gas prices received for sales of gas from the Swan Creek Field averaged \$3.94 per Mcf in 2013, \$3.35 per Mcf in 2012, and \$4.28 per Mcf in 2011. Oil prices received for sales of oil from the Swan Creek field averaged \$92.66 per barrel in 2013, \$88.29 per barrel in 2012, and \$87.33 per barrel in 2011. Swan Creek field results during 2013 reflect only operating from the beginning of 2013 until the field was sold in August 2013.

The Company's production costs and taxes were approximately \$5.5 million in 2013, \$7.2 million in 2012, and \$5.9 million in 2011. The \$(1.7) million decrease in 2013 related primarily to a \$(0.4) million decrease in Kansas property taxes primarily related to successful appeals of 2012 property taxes, \$(0.2) million reduction in Gulf of Mexico related operating cost as the Management Agreement with Hoactzin expired in December 2012, \$(0.2) million decrease in Methane Project and electric generation costs, and \$(0.2) million related to Swan Creek and pipeline asset cost as these were sold in August 2013. The \$1.3 million increase in 2012 was primarily due to a \$0.3 million increase in Kansas field expenses, a \$0.3 million increase in Kansas property taxes, and a \$0.3 million increase in Methane Project and electric generation costs.

Depreciation, depletion, and amortization was approximately \$2.9 million in 2013, \$3.4 million in 2012, and \$2.5 million in 2011. The \$(0.5) million decrease in 2013 was primarily related to lower oil and gas depletion expense due to lower sales volume partially offset by an increase in the depletion rate. The \$0.9 million increase in 2012 was primarily related to higher oil and gas depletion expense due to increased sales volumes and an increase in the depletion rate.

The Company's general and administrative cost was approximately \$2.1 million in 2013, \$2.6 million in 2012, and \$2.3 million in 2011. The \$(0.5) million decrease in 2013 was a \$(0.34) million decrease in bad debt expense as the \$0.26 million recorded for Hoactzin related receivables was decreased by \$(0.1) million in 2013 as a portion of the related payables were paid and or re-billed to Hoactzin, and a \$(0.2) million decrease in legal, accounting, and consulting expenses. The \$0.3 million increase in 2012 was primarily related to a \$0.26 million allowance recorded in 2012 for Hoactzin related receivables, a \$0.1 million increase in tax preparation and consulting costs related to reviews of prior year tax returns, a \$0.1 million increase in non-tax consulting cost, partially offset by a \$(0.17) million decrease in bonus cost. The 2013, 2012, and 2011 cost included non-cash charges related to stock options of \$0.05 million, \$0.2 million, and \$0.1 million, respectively.

Interest expense was \$357,000 in 2013, \$743,000 in 2012, and \$642,000 in 2011. The \$(386,000) decrease in interest expense in 2013 was primarily due to a \$6.5 million decrease in the average credit facility balance from \$12.6 million during 2012 to \$6.1 million during 2013. The decrease was primarily due to low drilling and polymer activities during the second half of 2012 and all of 2013 resulting in operating cash flows in excess of drilling and polymer costs being used to pay down the credit facility. The \$101,000 increase in interest expense in 2012 was due to increased borrowings from the Company's credit facility with F&M Bank to supplement funding of material inventory purchases in early 2012 and to supplement funding of the Company's 2012 drilling and polymer program. Although the credit facility balance at December 31, 2012 was \$1.4 million lower than the balance at December 31, 2011, the average balance increased from \$10.6 million during 2011 to \$12.6 million during 2012.

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During 2013, the Company did not have any open derivative positions. During 2012, the Company recorded a \$(0.14) million loss on derivatives. The 2012 loss on derivatives was comprised solely of an unrealized loss. During 2011, the Company recorded a \$(0.41) million loss on derivatives. The 2011 loss was comprised of a \$0.45 million unrealized gain, offset by \$(0.86) million of settlement payments made to Macquarie Bank Limited (“Macquarie”) pursuant to a hedging agreement it entered into with Macquarie in August 2009 (see, Item 7A, “Commodity Risk”).

In 2012, the Company recorded a non-cash impairment of its pipeline assets in the amount of \$5.2 million (\$3.4 million net of tax effect). The pipeline assets were classified as assets held for sale in the Company’s Consolidated Balance Sheet as of December 31, 2012. These write downs resulted from the Company’s assessment that cash flows generated from the pipeline were insufficient to recover the pipeline’s net book value. During 2012 and 2010, the Company received expressions of interest from potential purchasers of the pipeline asset which were significantly below the asset’s pre write down net book values. These expressions of interest indicated that the carrying amount of the pipeline may not be recoverable. At December 31, 2012, the Company was in the process of negotiating an agreement to sell the pipeline assets and the Swan Creek Field wells and associated equipment. Preliminary allocation of the sales value to the pipeline assets indicated a write down of approximately \$5.2 million, before tax effect, was necessary. The pipeline asset was sold in August 2013.

The Company recorded income tax expense on continuing operations of \$2.0 million in 2013, \$2.3 million in 2012, and \$0.3 million in 2011. The tax expense in 2011 was impacted by removal of the \$1.7 million valuation allowance. Had this valuation allowance not been removed the Company would have recorded tax expense of \$2.0 million in 2011. (See Note 14. Income Taxes in Notes to Consolidated Financial Statements)

Liquidity and Capital Resources

At December 31, 2013, the Company had a revolving credit facility with F&M Bank & Trust Company (“F&M Bank”). This is the Company’s primary source to fund working capital and future capital spending. Under the credit facility, loans and letters of credit are available to the Company on a revolving basis in an amount outstanding not to exceed the lesser of \$40 million or the Company’s borrowing base in effect from time to time. As of December 31, 2013, the Company’s borrowing base was \$17.5 million. The borrowing base was reduced to \$14.3 million with the March 27, 2014 amendment to the credit agreement. The credit facility is secured by substantially all of the Company’s producing and non-producing oil and gas properties, the Company’s Methane Project assets, and the electric generation assets. The credit facility includes certain covenants with which the Company is required to comply. These covenants include leverage, interest coverage, minimum liquidity, and general and administrative coverage ratios. During 2013, 2012, and 2011, the Company was in compliance with all covenants.

On March 6, 2013, the Company’s senior credit facility with F&M Bank after F&M Bank’s semiannual review of the Company’s then owned producing properties was amended to reduce the Company’s borrowing base from \$21.5 million to \$20.5 million and extend the term of the facility to January 27, 2015. The interest rate remained the greater of prime plus 0.25% or 5.25% per annum.

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On October 24, 2013, the Company's senior credit facility with F&M Bank after F&M Bank's semiannual review of the Company's then owned producing properties was amended to decrease the Company's borrowing base from \$20.5 million to \$17.5 million. This decrease in the Company's borrow base was primarily related to a lower reserve base used at the mid-year borrowing base review as a result of production during the first six months of 2013 with no offsetting reserve additions from drilling or polymers. The borrowing base remains subject to the existing periodic redetermination provision in the credit facility. The interest rate was modified from the greater of prime plus 0.25% or 5.25% per annum, to prime plus 0.50%.

On March 27, 2014, the Company's senior credit facility with F&M Bank after F&M Bank's semiannual review of the Company's currently owned producing properties was amended to reduce the Company's borrowing base from \$17.5 million to \$14.3 million and extend the term of the facility to January 27, 2016. The interest rate remained prime plus 0.50%.

The total borrowing by the Company under the facility at December 31, 2013 and December 31, 2012 was \$3.3 million and \$10.1 million, respectively. The next borrowing base review will take place in July 2014.

Net cash provided by operating activities from continuing operations was \$8.0 million in 2013, \$9.3 million in 2012, and \$8.7 million in 2011. Net cash used in operating activities from discontinued operations was \$(85,000) in 2013, \$(265,000) in 2012, and \$(237,000) in 2011. The decrease in cash provided by operating activities in 2013 was primarily related to a decrease in sales volumes, partially offset by increased oil prices, reduction in production costs and taxes, reduction in general and administrative costs and \$1.3 million increase in cash flow provided by working capital. The increase in cash provided by operating activities from continuing operations in 2012 was primarily due to a \$3.3 million increase related to increased sales volumes, partially offset by a \$(1.3) million increase in production costs and taxes and a \$(1.2) million decrease in changes in working capital. Cash flow provided by working capital was \$0.2 million in 2013, cash flow used in working capital was \$(1.1) million in 2012, and \$0.3 million was provided by working capital in 2011. The difference in changes in working capital in 2013 as compared to 2012 was primarily posting cash collateral related to the appeal bond in 2012 and 2012 increase in equipment and materials inventory, partially offset by lower receivables in 2013 related to lower year-end revenues in 2013 as compared to 2012. The difference in changes in working capital in 2012 as compared to 2011 was primarily related to a decrease in accounts payable related primarily to a reduction in year-end drilling and polymer activity compared to 2011, posting of cash collateral related to the appeal bond, and an increase in equipment and materials inventory.

Net cash used in investing activities from continuing operations was \$2.2 million in 2013, \$7.6 million in 2012, and \$10.4 million in 2011. The \$5.4 million decrease in investing activities in 2013 as compared to 2012 was due to decreased drilling and polymer activities in 2013 as compared to 2012, 2012 additions to the Methane Project and electric generator, partially offset by the \$1.0 million received in 2012 for payment in lieu of tax credits related to the Methane Project and electric generator. The \$2.8 million decrease in investing activities in 2012 as compared to 2011 was due to a \$1.2 million decrease in derivative cost, receipt of a \$1.0 million payment in lieu of tax credits related to the Methane Project and electric generator, a \$0.35 million reduction in capital spending related to the Methane Facility, and a \$0.2 million reduction in drilling and polymer cost. In 2013, net cash provided by investing activities from discontinued operations was \$1.4 million which represented the proceeds received from the sale of the pipeline assets in August 2013.

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In 2013 and 2012, \$(5.7) million and \$(1.8) million respectively was used in financing activities from continuing operations to pay down the Company's credit facility. In 2011, \$1.6 million was provided by financing activities from continuing operations from bank funding which was used primarily to fund drilling and polymer activities during 2011. Net cash used in financing activities from discontinued operations in 2013 was \$(1.3) million. Net cash provided by financing activities from discontinued operations was \$0.27 million in 2012 and \$0.24 million in 2011. This funding in 2012 and in 2011 was used to finance the Company's pipeline operations.

Critical Accounting Policies

The Company prepares its Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America, which require the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the year. Actual results could differ from those estimates. The Company considers the following policies to be the most critical in understanding the judgments that are involved in preparing the Company's financial statements and the uncertainties that could impact the Company's results of operations, financial condition and cash flows.

Revenue Recognition

Revenues are recognized based on actual volumes of oil, natural gas, methane gas, and electricity sold to purchasers at a fixed or determinable price, when delivery has occurred and title has transferred, and collectability is reasonably assured. Crude oil is stored and at the time of delivery to the purchasers, revenues are recognized. Natural gas meters are placed at the customer's location and usage is billed each month. There were no material natural gas imbalances at December 31, 2013. Methane gas and electricity sales meters are located at the Carter Valley landfill site and methane sales and electricity generation sales are billed each month.

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Full Cost Method of Accounting

The Company follows the full cost method of accounting for oil and gas property acquisition, exploration, and development activities. Under this method, all costs incurred in connection with acquisition, exploration and development of oil and gas reserves are capitalized. Capitalized costs include lease acquisitions, seismic related costs, certain internal exploration costs, drilling, completion, and estimated asset retirement costs. The capitalized costs of oil and gas properties, plus estimated future development costs relating to proved reserves and estimated asset retirement costs which are not already included net of estimated salvage value, are amortized on the unit-of-production method based on total proved reserves. The Company has determined its reserves based upon reserve reports provided by LaRoche Petroleum Consultants Ltd. since 2009. The costs of unproved properties are excluded from amortization until the properties are evaluated, subject to an annual assessment of whether impairment has occurred. The Company had \$736,000 and \$457,000 in unevaluated properties as of December 31, 2013 and 2012, respectively. Proceeds from the sale of oil and gas properties are accounted for as reductions to capitalized costs unless such sales cause a significant change in the relationship between costs and the estimated value of proved reserves, in which case a gain or loss is recognized. At the end of each reporting period, the Company performs a “ceiling test” on the value of the net capitalized cost of oil and gas properties. This test compares the net capitalized cost (capitalized cost of oil and gas properties, net of accumulated depreciation, depletion and amortization and related deferred income taxes) to the present value of estimated future net revenues from oil and gas properties using an average price (arithmetic average of the beginning of month prices for the prior 12 months) and current cost discounted at 10% plus cost of properties not being amortized and the lower of cost or estimated fair value of unproven properties included in the cost being amortized (ceiling). If the net capitalized cost is greater than the ceiling, a write-down or impairment is required. A write-down of the carrying value of the asset is a non-cash charge that reduces earnings in the current period. Once incurred, a write-down may not be reversed in a later period.

Oil and Gas Reserves/Depletion, Depreciation, and Amortization of Oil and Gas Properties

The capitalized costs of oil and gas properties, plus estimated future development costs relating to proved reserves and estimated asset retirement costs which are not already included net of estimated salvage value, are amortized on the unit-of-production method based on total proved reserves. The costs of unproved properties are excluded from amortization until the properties are evaluated, subject to an annual assessment of whether impairment has occurred.

The Company’s proved oil and gas reserves as of December 31, 2013 were determined by LaRoche Petroleum Consultants, Ltd. Projecting the effects of commodity prices on production, and timing of development expenditures includes many factors beyond the Company’s control. The future estimates of net cash flows from the Company’s proved reserves and their present value are based upon various assumptions about future production levels, prices, and costs that may prove to be incorrect over time. Any significant variance from assumptions could result in the actual future net cash flows being materially different from the estimates.

Asset Retirement Obligations

The Company’s asset retirement obligations relate to the plugging, dismantling, and removal of wells drilled to date. The Company follows the requirements of FASB ASC 410, “Asset Retirement Obligations and Environmental Obligations”. Among other things, FASB ASC 410 requires entities to record a liability and corresponding increase in long-lived assets for the present value of material obligations associated with the retirement of tangible long-lived assets. Over the passage of time, accretion of the liability is recognized as an operating expense and the capitalized cost is depleted over the estimated useful life of the related asset. If the estimated future cost of the asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the long-lived asset. Revisions to estimated asset retirement obligations can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment. The Company currently uses an estimated useful life of wells ranging from 30-40 years. Management continues to periodically evaluate the

appropriateness of these assumptions.

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Income Taxes

Income taxes are reported in accordance with U.S. GAAP, which requires the establishment of deferred tax accounts for all temporary differences between the financial reporting and tax bases of assets and liabilities, using currently enacted federal and state income tax rates. In addition, deferred tax accounts must be adjusted to reflect new rates if enacted into law. Temporary differences result principally from federal and state net operating loss carryforwards, differences in oil and gas property values resulting from a 2008 ceiling test write down, and differences in methods of reporting depreciation and amortization. Management routinely assesses the ability to realize our deferred tax assets and reduces such assets by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be recognized.

At December 31, 2013, federal net operating loss carryforwards amounted to approximately \$19.7 million which expire between 2019 and 2031. The total deferred tax asset was \$7.3 million and \$9.4 million at December 31, 2013 and 2012, respectively.

Realization of deferred tax assets is contingent on the generation of future taxable income. As a result, management considers whether it is more likely than not that all or a portion of such assets will be realized during periods when they are available, and if not, management provides a valuation allowance for amounts not likely to be recovered.

Management periodically evaluates tax reporting methods to determine if any uncertain tax positions exist that would require the establishment of a loss contingency. A loss contingency would be recognized if it were probable that a liability has been incurred as of the date of the financial statements and the amount of the loss can be reasonably estimated.

The amount recognized is subject to estimates and management's judgment with respect to the likely outcome of each uncertain tax position. The amount that is ultimately incurred for an individual uncertain tax position or for all uncertain tax positions in the aggregate could differ from the amount recognized.

Although management considers our valuation allowance as of December 31, 2013 and 2012 adequate, material changes in these amounts may occur in the future based on tax audits and changes in legislation.

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Recent Accounting Pronouncements

In July 2013, the FASB issued ASU 2013-11 Income Taxes (Topic 740), Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists. This guidance provides that an unrecognized tax benefit, or a portion thereof, should be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward, except to the extent that a net operating loss carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date to settle any additional income taxes that would result from disallowance of a tax position, or the tax law does not require the entity to use, and the entity does not intend to use, the deferred tax asset for such purpose, then the unrecognized tax benefit should be presented as a liability. This guidance is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. Early adoption and retrospective application is permitted. The Company does not expect this to impact its operating results, financial position, or cash flows.

Contractual Obligations

The following table summarizes the Company's contractual obligations due by period as of December 31, 2013 (in thousands):

Contractual Obligations	Total	2014	2015	2016	2017
Long-Term Debt Obligations ¹	\$3,457	\$82	\$59	\$3,316	\$ -
Operating Lease Obligations	99	29	30	34	6
Estimated Interest on Long-Term Debt Obligations	322	131	128	63	-
Total	\$3,878	\$242	\$217	\$3,413	\$ 6

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISKS

Commodity Risk

The Company's major market risk exposure is in the pricing applicable to its oil and gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas production. Historically, prices received for oil and gas production have been volatile and unpredictable and price volatility is expected to continue. Monthly oil price realizations ranged from a low of \$84.94 per barrel to a high of \$99.83 per barrel during 2013. Gas prices realizations ranged from monthly low of \$2.46 per Mcf to a monthly high of \$4.29 per Mcf during the same period.

In order to help mitigate commodity price risk, the Company has entered into a long term fixed price contract for MMC gas sales. On August 27, 2009, the Company entered into a five-year fixed price gas sales contract with Atmos Energy Marketing, LLC, ("AEM") in Houston, Texas, a nonregulated unit of Atmos Energy Corporation (NYSE: ATO) for the sale of the methane component of landfill gas produced by MMC at the Carter Valley Landfill. The agreement provides for the sale of up to 600 MMBtu per day. The contract is effective beginning with September 2009 gas production and ends July 31, 2014. The agreed contract price of over \$6 per MMBtu was a premium to the then current five-year strip price for natural gas on the NYMEX futures market.

¹ The credit facility maturity date of January 27, 2016 is based on the March 27, 2014 amendment to the credit agreement.

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In addition, during 2010, 2011, and 2012, the Company participated in derivative agreements on a specified number of barrels of oil of its production. The Company did not participate in any derivative agreements during 2013, but may participate in derivative activities in the future. These agreements were primarily intended to help maintain and stabilize cash flow from operations if lower oil prices returned.

Interest Rate Risk

At December 31, 2013, the Company had debt outstanding of approximately \$3.5 million including, as of that date, \$3.3 million owed on its credit facility with F&M Bank. The interest rate on the credit facility is variable at a rate equal to the prime rate plus 0.50%. The Company's remaining debt of \$0.2 million has fixed interest rates ranging from 3.9% to 7.25%. As a result, the Company annual interest cost in 2013 fluctuated based on short-term interest rates on approximately 94% of its total debt outstanding at December 31, 2013. During 2013, the Company paid approximately \$325,000 of interest on the F&M Bank line of credit. The impact on interest expense and the Company's cash flows of a 10% increase in the interest rate on the F&M Bank credit facility would be approximately \$12,000 assuming borrowed amounts under the credit facility remained at the same amount owed as of December 31, 2013. The Company did not have any open derivative contracts relating to interest rates at December 31, 2013.

Forward-Looking Statements and Risk

Certain statements in this Report, including statements of the future plans, objectives, and expected performance of the Company, are forward-looking statements that are dependent upon certain events, risks and uncertainties that may be outside the Company's control, and which would cause actual results to differ materially from those anticipated. Some of these include, but are not limited to, the market prices of oil and gas, economic and competitive conditions, inflation rates, legislative and regulatory changes, financial market conditions, political and economic uncertainties of foreign governments, future business decisions, and other uncertainties, all of which are difficult to predict.

There are numerous uncertainties inherent in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from estimates. The drilling of exploratory wells can involve significant risks, including those related to timing, success rates and cost overruns. Lease and rig availability, complex geology, and other factors can also affect these risks. Additionally, fluctuations in oil and gas prices or prolonged periods of low prices may substantially adversely affect the Company's financial position, results of operations, and cash flows.

ITEM 8. FINANCIAL STATEMENTS AND
SUPPLEMENTARY DATA

The financial statements and supplementary data commence on page F-1.

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

None.

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ITEM 9A. CONTROLS AND PROCEDURES

The Company's Chief Executive Officer and Chief Financial Officer, and other members of management have evaluated the effectiveness of the Company's disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)). Based on such evaluation, the Company's Chief Executive Officer and Chief Financial Officer have concluded that the Company's disclosure controls and procedures, as of the end of the period covered by this Report, were adequate and effective to provide reasonable assurance that information required to be disclosed by the Company in reports that it files or submits under the Exchange Act, is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms. As a result of the resignation of Jeffrey R. Bailey as the Company's Chief Executive Officer on June 28, 2013 and the appointment by the Board of Michael J. Rugen, the Company's Chief Financial Officer to also serve as Chief Executive Officer on an interim basis, Mr. Rugen is acting in both capacities and has executed the accompanying certifications as to both offices.

The effectiveness of a system of disclosure controls and procedures is subject to various inherent limitations, including cost limitations, judgments used in decision making, assumptions about the likelihood of future events, the soundness of internal controls, and fraud. Due to such inherent limitations, there can be no assurance that any system of disclosure controls and procedures will be successful in preventing all errors or fraud, or in making all material information known in a timely manner to the appropriate levels of management.

Managements Annual Report on Internal Control Over Financial Reporting

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) promulgated under the Securities Exchange Act of 1934. Internal control over financial reporting refers to the process designed by, or under the supervision of the Company's Chief Executive Officer and Chief Financial Officer, and effected by the Company's Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, and includes those policies and procedures that:

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

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

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

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Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness into 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.

Under the supervision and with the participation of the Company's management, including the Chief Executive Officer and the Chief Financial Officer, the Company's management conducted an evaluation of the effectiveness of the Company internal control over financial reporting as of December 31, 2013. In making this assessment, the Company's management used the criteria set forth in the framework in "Internal Control-Integrated-Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on the evaluation conducted under the framework in "Internal Control- Integrated Framework," issued by COSO the Company's management concluded that the Company's internal control over financial reporting was effective as of December 31, 2013.

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

Changes in Internal Control Over Financial Reporting

As part of a continuing effort to improve the Company's business processes, management is evaluating its internal controls and may update certain controls to accommodate any modifications to its business processes or accounting procedures. During the year ended December 31, 2013, certain internal control procedures previously performed by the former Chief Executive Officer are now being performed by the Company's General Counsel and Audit Committee. There have been no other changes to the Company's system of internal control over financial reporting during the year ended December 31, 2013 that have materially affected, or are reasonably likely to materially affect, the Company's system of controls over financial reporting.

ITEM 9B. OTHER INFORMATION

On January 3, 2014, options to purchase 25,000 common shares at \$0.41 per share were issued to the Company's non-executive directors. These options fully vested upon grant date and will expire on January 2, 2019.

On March 27, 2014, the Company's senior credit facility with F&M Bank and Trust Company, N.A. of Dallas, Texas (F&M Bank") after F&M Bank's semiannual review of the Company's currently owned producing properties was amended to decrease the Company's borrowing base from \$17.5 million to \$14.3 million and extend the term of the facility to January 27, 2016. The borrowing base remains subject to the existing periodic redetermination provisions in the credit facility. The interest rate remained prime plus 0.50% per annum. The maximum line of credit of the Company under the F&M Bank credit facility remained \$40 million and the Company's outstanding borrowing under the facility as of March 27, 2014 was approximately \$1.8 million.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Identification of Directors and Executive Officers

NAME	POSITIONS HELD	DATE OF INITIAL ELECTION OR DESIGNATION	AGE
Matthew K. Behrent	Director	03/27/2007	43
Hughree F. Brooks	Director	12/03/2010	59
Peter E. Salas	Director; Chairman of the Board	10/08/2002 10/21/2004	59
Richard M. Thon	Director	11/22/2013	58
Michael J. Rugen	Chief Financial Officer; Chief Executive Officer (interim)	09/28/2009 06/24/2013	53
Cary V. Sorensen	Vice-President; General Counsel; Secretary	07/09/1999	65

Business ExperienceDirectors

Matthew K. Behrent is currently the Executive Vice President, Corporate Development of EDCI Holdings, Inc, a company that is currently engaged in carrying out a plan of dissolution. Before joining EDCI in June, 2005, Mr. Behrent was an investment banker, working as a Vice-President at Revolution Partners, a technology focused investment bank in Boston, from March 2004 until June 2005 and as an associate in Credit Suisse First Boston Corporation's technology mergers and acquisitions group from June 2000 until January 2003. From June 1997 to May 2000, Mr. Behrent practiced law, most recently with Cleary, Gottlieb, Steen & Hamilton in New York, advising financial sponsors and corporate clients in connection with financings and mergers and acquisitions transactions. Mr. Behrent received his J.D. from Stanford Law School in 1997, and his B.A. in Political Science and Political Theory from Hampshire College in 1992. He became a Director of the Company on March 27, 2007. He is also a Director and Chairman of the Audit Committee of Asure Software, Inc. (NASDAQ: ASUR). The experience, qualifications, attributes, and skills gained by Mr. Behrent in these sophisticated legal and financial positions directly apply to and support the financial oversight of the Company's operations and lead to the conclusion that Mr. Behrent should serve as a Director of the Company.

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Hughree F. Brooks in 2010 co-founded Powerhouse Energy Solutions LLC, a company engaged in providing equipment and services to clients in renewable and alternative energy industries in the United States and abroad. Powerhouse is a provider of solar energy systems as well as advisory services to biofuel producers. Since 1998, Mr. Brooks has continuously provided consulting services in the oil and gas exploration industry. These services include land management, landowner representation, deal structuring and financing, and expert witness services. Mr. Brooks has 35 years of experience as a land manager with independent and major oil companies including Amoco Production, Mitchell Energy, Ladd Petroleum, Phoenix Exploration and Renown Petroleum Inc. His clients own in excess of 16,000 acres in South Louisiana with a long history of oil and gas production. In 2002, he founded and continues to serve as the Executive Director of Friends Of The Farm, a Texas nonprofit. Mr. Brooks is a licensed attorney who received his J.D. from Loyola Law School in 1980. He received a Bachelor of Science Degree in 1976 from Loyola University in New Orleans. The experience, qualifications, and skills of Mr. Brooks gained in an extensive career in the oil and gas exploration and production industry are directly related to the operations of the Company and lead to the conclusion that Mr. Brooks should serve as a Director of the Company.

Peter E. Salas has been President of Dolphin Asset Management Corp. and its related companies since he founded it in 1988. Prior to establishing Dolphin, he was with J.P. Morgan Investment Management, Inc. for ten years, becoming Co-manager, Small Company Fund and Director-Small Cap Research. He received an A.B. degree in Economics from Harvard in 1978. Mr. Salas was elected to the Board of Directors on October 8, 2002. Mr. Salas also served on the board of Williams Controls, Inc. During a portion of the last five years, Mr. Salas also served on the Board of Directors of Southwall Technologies, Inc. The business experience, attributes, and skills gained by Mr. Salas in these sophisticated financial positions, together with his service as director of other public companies and his capacity as controlling person of the Company's largest shareholder directly apply to and support his qualification as a director, and lead to the conclusion that Mr. Salas should serve as a Director of the Company.

Richard M. Thon began a career with ARAMARK Corporation in 1987. ARAMARK is based in Philadelphia, has 250,000 employees worldwide, and provides food services, facilities management, and uniform and career apparel to health care institutions, universities, and businesses in 22 countries. Mr. Thon served in various capacities in the Corporate Finance Department of ARAMARK culminating with the position of Assistant Treasurer when he retired in June 2002. His responsibilities included bank credit agreements, public debt issuance, interest rate risk management, foreign subsidiary credit agreements, foreign exchange, letters of credit, insurance finance, off-balance-sheet finance, and real estate and equipment leasing. Prior to joining ARAMARK, Mr. Thon was a Vice President in the International Department of Mellon Bank. Since his retirement in 2002, Mr. Thon has served in a variety of volunteer charitable and civic activities. In addition, during a portion of the past five years, he served on the boards of ACT Conferencing, Inc. and Horizons Unlimited Geriatric Education Corporation. Mr. Thon currently serves on the board of Boston Restaurant Associates, Inc. Mr. Thon received a B.A. in Economics degree from Yale College in 1977 and a Masters of Business Administration degree in Finance from The Wharton School, University of Pennsylvania in 1979. Mr. Thon's experience in the fields of banking and finance directly apply to the business needs of the Company and lead to the conclusion that he will provide significant benefit to the Board and that he is qualified to serve as a Director of the Company.

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Officers

Michael J. Rugen was named Chief Financial Officer of the Company in September 2009 and as interim Chief Executive Officer in June 2013. He is a certified public accountant (Texas) with over 30 years of experience in exploration, production and oilfield service. Prior to joining the Company, Mr. Rugen spent 2 years as Vice President of Accounting and Finance for Nighthawk Oilfield Services. From 2001 to June 2007, he was a Manager/Sr. Manager with UHY Advisors, primarily responsible for managing internal audit and Sarbanes-Oxley 404 engagements for various oil and gas clients. In 1999 and 2000, Mr. Rugen provided finance and accounting consulting services with Jefferson Wells International. From 1982 to 1998, Mr. Rugen held various accounting and management positions at BHP Petroleum, with accounting responsibilities for onshore and offshore US operations as well as operations in Trinidad and Bolivia. Mr. Rugen earned a Bachelor of Science in Accounting in 1982 from Indiana University.

Cary V. Sorensen is a 1976 graduate of the University of Texas School of Law and has undergraduate and graduate degrees from North Texas State University and Catholic University in Washington, D.C. Prior to joining the Company in July 1999, he had been continuously engaged in the practice of law in Houston, Texas relating to the energy industry since 1977, both in private law firms and a corporate law department, serving for seven years as senior counsel with the oil and gas litigation department of a Fortune 100 energy corporation in Houston before entering private practice in June, 1996. He has represented virtually all of the major oil companies headquartered in Houston as well as local distribution companies and electric utilities in a variety of litigated and administrative cases before state and federal courts and agencies in nine states. These matters involved gas contracts, gas marketing, exploration and production disputes involving royalties or operating interests, land titles, oil pipelines and gas pipeline tariff matters at the state and federal levels, and general operation and regulation of interstate and intrastate gas pipelines. He has served as General Counsel of the Company since July 9, 1999.

Family and Other Relationships

There are no family relationships between any of the present directors or executive officers of the Company.

Involvement in Certain Legal Proceedings

To the knowledge of management, no director, executive officer or affiliate of the Company or owner of record or beneficially of more than 5% of the Company's common stock is a party adverse to the Company or has a material interest adverse to the Company in any proceeding.

To the knowledge of management, during the past ten years, unless specifically indicated below with respect to any numbered item, no present director, executive officer or person nominated to become a director or an executive officer of the Company:

Filed a petition under the federal bankruptcy laws or any state insolvency law, nor had a receiver, fiscal agent or similar officer appointed by a court for the business or property of such person, or any partnership in which he or she was a general partner at or within two years before the time of such filing, or any corporation or business association of which he or she was an executive officer at or within two years before the time of such filing; provided however that the Company's Chief Financial Officer Michael J. Rugen during 2007 through mid 2009 was (1) Vice President of Accounting and Finance for Nighthawk Oilfield Services in Houston, Texas (Nighthawk); Nighthawk filed for bankruptcy protection under Chapter 7 of the bankruptcy laws on July 10, 2009 and such fact was affirmatively disclosed to the Company's Board before Mr. Rugen was appointed to the position of Chief Financial Officer of the Company in September, 2009, and the Board determined that the circumstances surrounding bankruptcy filing did not disclose any reason to question the integrity or qualifications of Mr. Rugen for the position of Chief Financial Officer of the Company.

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(2) Was convicted in a criminal proceeding or named the subject of a pending criminal proceeding (excluding traffic violations and other minor offenses);

Was the subject of any order, judgment or decree, not subsequently reversed, suspended or vacated, of any court of competent jurisdiction, permanently or temporarily enjoining him or her from or otherwise limiting the following activities: (a) acting as a futures commission merchant, introducing broker, commodity trading advisor, commodity pool operator, floor broker, leverage transaction merchant, any other person regulated by the Commodity Futures Trading Commission, or an associated person of any of the foregoing, or as an investment adviser, underwriter, broker or dealer in securities, or as an affiliated person, director or employee of any investment company, bank, savings and loan association or insurance company, or engaging in or continuing any conduct or practice in connection with such activity; (b) engaging in any type of business practice; or (c) engaging in any activity in connection with the purchase or sale of any security or commodity or in connection with any violation of federal or state securities laws or federal commodities laws;

(4) Was the subject of any order, judgment or decree, not subsequently reversed, suspended or vacated, of any Federal or State authority barring, suspending or otherwise limiting him or her for more than 60 days from engaging in any activity described in paragraph 3(a) above, or being associated with any persons engaging in any such activity;

(5) Was found by a court of competent jurisdiction in a civil action or by the SEC to have violated any federal or state securities law, and the judgment in such civil action or finding by the SEC has not been subsequently reversed, suspended, or vacated;

(6) Was found by a court of competent jurisdiction in a civil action or by the Commodity Futures Trading Commission ("CFTC") to have violated any federal commodities law, and the judgment in such civil action or finding by the CFTC has not been subsequently reversed, suspended, or vacated;

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Was the subject of, or a party to, any federal or state judicial or administrative order, judgment, decree, or finding, not subsequently reversed, suspended or vacated, relating to an alleged violation of: (i) any federal or state securities or commodities law or regulation; (ii) any law or regulation respecting financial institutions or insurance companies including but not limited to a temporary or permanent injunction, order of disgorgement or restitution, civil money penalty or temporary or permanent cease and desist order, or removal or prohibition order; or (iii) any law or regulation prohibiting mail or wire fraud or fraud in connection with any business entity; or

Was the subject of, or a party to, any sanction or order, not subsequently reversed, suspended or vacated, of any self-regulatory organization (as defined in Section 3(a)(26) of the Exchange Act [15 U.S.C. 78c(a)(26)], any (8) registered entity (as defined in Section 1(a)(29) of the Commodity Exchange Act [7 U.S.C. 1(a)(29)], or any equivalent exchange, association, entity or organization that has disciplinary authority over its members or persons associated with a member.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires the Company's executive officers, directors and persons who beneficially own more than 10% of the Company's Common Stock to file initial reports of ownership and reports of changes in ownership with the SEC no later than the second business day after the date on which the transaction occurred unless certain exceptions apply. In fiscal 2013, the Company, its officers and directors and its shareholders owning more than 10% of its common stock were not delinquent in filing of any of their Form 3, 4, and 5 reports.

Code of Ethics

The Company's Board of Directors has adopted a Code of Ethics that applies to the Company's financial officers and executives officers, including its Chief Executive Officer and Chief Financial Officer. The Company's Board of Directors has also adopted a Code of Conduct and Ethics for Directors, Officers and Employees. A copy of these codes can be found at the Company's internet website at www.tengasco.com. The Company intends to disclose any amendments to its Codes of Ethics, and any waiver from a provision of the Code of Ethics granted to the Company's President, Chief Financial Officer or persons performing similar functions, on the Company's internet website within five business days following such amendment or waiver. A copy of the Code of Ethics can be obtained free of charge by writing to Cary V. Sorensen, Secretary, Tengasco, Inc., 123 Center Park Drive, Suite 104, Knoxville, TN 37922.

Audit Committee

In 2013, directors Hughree F. Brooks and Matthew K. Behrent, were the members of the Board's Audit Committee until November 24, 2013 when director Richard M. Thon replaced Mr. Brooks on the Audit Committee. Mr. Behrent was the Chairman of the Committee and the Board of Directors determined that both Mr. Behrent and Mr. Thon were each an "audit committee financial expert" as defined by applicable Securities and Exchange Commission ("SEC") regulations and the NYSE MKT Rules. Each of the members of the Audit Committee met the independence and experience requirements of the NYSE MKT Rules, the applicable Securities Laws, and the regulations and rules promulgated by the SEC. The Audit Committee met each quarter and a total of four (4) times in Fiscal 2013 with the Company's auditors, including discussing the audit of the Company's year-end financial statements.

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The Audit Committee adopted an Audit Committee Charter during fiscal 2001. In 2004, the Board adopted an amended Audit Committee Charter, a copy of which is available on the Company's internet website, www.tengasco.com. The Audit Committee Charter fully complies with the requirements of the NYSE MKT Rules. The Audit Committee reviews and reassesses the Audit Committee Charter annually.

The Audit Committee's functions are:

To review with management and the Company's independent auditors the scope of the annual audit and quarterly statements, significant financial reporting issues and judgments made in connection with the preparation of the Company's financial statements;

To review major changes to the Company's auditing and accounting principles and practices suggested by the independent auditors;

To monitor the independent auditor's relationship with the Company;

To advise and assist the Board of Directors in evaluating the independent auditor's examination;

To supervise the Company's financial and accounting organization and financial reporting;

To nominate, for approval of the Board of Directors, a firm of certified public accountants whose duty it is to audit the financial records of the Company for the fiscal year for which it is appointed; and

To review and consider fee arrangements with, and fees charged by, the Company's independent auditors.

Changes in Board Nomination Procedures

In 2013, there were no changes to the procedures adopted by the Board for nominations for the Board of Directors. Those procedures were last set forth in the Company's Proxy Statement filed on September 6, 2013 for the Company's Annual Meeting held on October 17, 2013 and are posted on the Company's internet website at www.tengasco.com. In the event of any such amendment to the procedures, the Company intends to disclose the amendments on the Company's internet website within five business days following such amendment.

Table of contentsITEM 11. EXECUTIVE
COMPENSATIONExecutive Officer Compensation

The following table sets forth a summary of all compensation awarded to, earned or paid to, the Company's Chief Executive Officer, Chief Financial Officer and other executive officers whose compensation exceeded \$100,000 during fiscal years ended December 31, 2013 and December 31, 2012.

SUMMARY COMPENSATION TABLE

Name and Principal Position	Year	Salary (\$)	Bonus (\$)	Option Awards (\$)	All Other Compensation ² (\$)	Total (\$)
Jeffrey R. Bailey, Chief Executive Officer (former) ³	2013	98,500	27,000	-	6,933	132,433
Michael J. Rugen, Chief Financial Officer Chief Executive Officer (interim) ⁴	2012	189,750	-	-	13,628	203,378
Michael J. Rugen, Chief Financial Officer	2013	155,770	52,500	-	14,828	223,098
Cary V. Sorensen, General Counsel	2012	150,000	-	-	13,500	163,500
Cary V. Sorensen, General Counsel	2013	137,940	-	-	10,221	148,161
Charles P. McInturff, Vice President ⁵	2012	137,940	-	-	9,697	147,637
Charles P. McInturff, Vice President ⁵	2013	182,970	-	-	12,335	195,305
	2012	92,500	-	-	17,842	110,342

² The amounts in this column consist of the Company's matching contributions to its 401 (k) plan, personal use of company vehicles, and the portion of company-wide group term life insurance premiums allocable to these named executive officers.

³ Mr. Bailey resigned as Chief Executive Officer of the Company on June 28, 2013.

⁴ Mr. Rugen was appointed interim Chief Executive Officer on June 28, 2013. The information for Mr. Rugen for 2013 includes compensation for his services as both CEO and CFO.

⁵ Mr. McInturff resigned as Vice President of the Company on December 16, 2013.

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Outstanding Equity Awards at Fiscal Year-End

Name	OPTION AWARDS		Option price	Option expiration date
	Number of securities underlying unexercised options exercisable ⁶	Number of securities underlying unexercised options unexercisable		
Michael J. Rugen	320,000	80,000	\$ 0.50	9/27/2015
Cary V. Sorensen	74,000	-	\$ 0.44	8/29/2015

Option and Award Exercises

Mr. McInturff received a \$59,520 payment in lieu of exercising his fully exercisable options to purchase 400,000 shares. This payment is the same economic benefit to Mr. McInturff as if he had made a cashless exercise of the options, and the Company elected to make such payment in lieu of issuing the shares and the resulting dilutive effect of doing so. These options were to expire on February 1, 2013. No other options were exercised during 2013.

Employment Contracts

On July 31, 2013, the Company and its Exploration Manager Rod Tremblay entered into an agreement that provided that if his employment was terminated without cause prior to July 31, 2014, the Company would pay in a lump sum the remaining amount that would have been paid from date of termination to July 31, 2014, plus cost of the individual health insurance premium that would have been paid by the company through July 31, 2014.

On September 18, 2013, the Company and its Chief Financial Officer and interim Chief Executive Officer Michael J. Rugen entered into a written Compensation Agreement as reported on Form 8-K filed on September 24, 2013. Under the terms of the Compensation Agreement, Mr. Rugen's salary will increase from \$150,000 to \$170,000 per year in his capacity as Chief Financial Officer, and he will receive a bonus of \$7,500 per quarter for each quarter during which he also serves as interim Chief Executive Officer. The Compensation agreement is not an employment contract, but does provide that in the event Mr. Rugen were terminated without cause, he would receive a severance payment in the amount of six month's salary in effect at the time of any such termination.

⁶ Mr. Rugen's 80,000 unexercisable share options will vest on 9/27/2014.

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There are presently no other employment contracts relating to any member of management. However, depending upon the Company's operations and requirements, the Company may offer long-term contracts to executive officers or key employees in the future.

Compensation and Stock Option Committee

The members of the Compensation/Stock Option Committee in Fiscal 2013 until November 24, 2013 were Matthew K. Behrent, Peter Salas, and Hughree F. Brooks with Mr. Brooks acting as Chairman. On November 24, 2013, Mr. Richard Thon replaced Mr. Salas on this Committee. Messrs. Behrent, Salas, Thon, and Brooks meet the current independence standards established by the NYSE MKT Rules to serve on this Committee.

The Board of Directors has adopted a charter for the Compensation/Stock Option Committee which is available at the Company's internet website, www.tengasco.com.

The Compensation/Stock Option Committee's functions, in conjunction with the Board of Directors, are to provide recommendations with respect to general and specific compensation policies and practices of the Company for directors, officers and other employees of the Company. The Compensation/Stock Option Committee expects to periodically review the approach to executive compensation and to make changes as competitive conditions and other circumstances warrant and will seek to ensure the Company's compensation philosophy is consistent with the Company's best interests and is properly implemented. The Committee determines or recommends to the Board of Directors for determination the specific compensation of the Company's Chief Executive Officer and all of the Company's other officers. Although the Committee may seek the input of the Company's Chief Executive Officer in determining the compensation of the Company's other executive officers, the Chief Executive Officer may not be present during the voting or deliberations with respect to his compensation. The Committee may not delegate any of its responsibilities unless it is to a subcommittee formed by the Committee, but only if such subcommittee consists entirely of directors who meet the independence requirements of the NYSE MKT Rules.

The Compensation/Stock Option Committee is also charged with administering the Tengasco, Inc. Stock Incentive Plan (the "Stock Incentive Plan"). The Compensation/Stock Option Committee has complete discretionary authority with respect to the awarding of options and Stock Appreciation Rights ("SARs"), under the Stock Incentive Plan, including, but not limited to, determining the individuals who shall receive options and SARs; the times when they shall receive them; whether an option shall be an incentive or a non-qualified stock option; whether an SAR shall be granted separately, in tandem with or in addition to an option; the number of shares to be subject to each option and SAR; the term of each option and SAR; the date each option and SAR shall become exercisable; whether an option or SAR shall be exercisable in whole, in part or in installments and the terms relating to such installments; the exercise price of each option and the base price of each SAR; the form of payment of the exercise price; the form of payment by the Company upon the exercise of an SAR; whether to restrict the sale or other disposition of the shares of common stock acquired upon the exercise of an option or SAR; to subject the exercise of all or any portion of an option or SAR to the fulfillment of a contingency, and to determine whether such contingencies have been met; with the consent of the person receiving such option or SAR, to cancel or modify an option or SAR, provided such option or SAR as modified would be permitted to be granted on such date under the terms of the Stock Incentive Plan; and to make all other determinations necessary or advisable for administering the Plan.

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The Compensation/Stock Option Committee met five (5) times in Fiscal 2013. The Committee has the authority to retain a compensation consultant or other advisors to assist it in the evaluation of compensation and has the sole authority to approve the fees and other terms of retention of such consultants and advisors and to terminate their services. The Committee did not retain any such consultants or advisors in 2013.

Compensation of Directors

The Board of Directors has resolved to compensate members of the Board of Directors for attendance at meetings at the rate of \$250 per day, together with direct out-of-pocket expenses incurred in attendance at the meetings, including travel. The Directors, as of the date of this Report, have waived all such fees due to them for prior meetings.

Members of the Board of Directors may also be requested to perform consulting or other professional services for the Company from time to time, although at this time no such arrangements are in place. The Board of Directors has reserved to itself the right to review all directors' claims for compensation on an ad hoc basis.

Board members currently receive fees from the Company for their services as director. They may also from time to time be granted stock options under the Tengasco, Inc. Stock Incentive Plan. A separate plan to issue cash and/or shares of stock to independent directors for service on the Board and various committees was authorized by the Board of Directors and approved by the Company's shareholders. A copy of the Plan is posted at the Company's website at www.tengasco.com. However, no award was made to any independent director under that separate plan in Fiscal 2013.

DIRECTOR COMPENSATION FOR FISCAL 2013

Name	Fees earned or Option awards paid in compensation cash		Total
	(⁷)	(⁷)	
Matthew K. Behrent	\$ 15,000	\$ 5,983	\$20,983
Hughree F. Brooks	\$ 15,000	\$ 5,983	\$20,983
Richard M. Thon	\$3,750	\$ -	\$3,750
Peter E. Salas	\$15,000	\$ 5,983	\$20,983

⁷ The amounts represented in this column are equal to the aggregate grant date fair value of the award computed in accordance with FASB ASC Topic 718, Compensation-Stock Compensation, in connection with options granted under the Tengasco, Inc. Stock Incentive Plan. See Note 13 Stock Options in the Notes to Consolidated Financial Statements included in the Company's Annual Report on Form 10-K for the year ended December 31, 2012 for information on the relevant valuation assumptions. As of December 31, 2012, Mr. Behrent held 143,750 unexercised options; Mr. Brooks held 43,750 unexercised options; and Mr. Salas held 143,750 unexercised options

Table of contentsITEM SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND
12. RELATED STOCKHOLDERS MATTERS

The following table sets forth the share holdings of those persons who own more than 5% of the Company's common stock as of March 17, 2014 with these computations being based upon 60,842,413 shares of common stock being outstanding as of that date and as to each shareholder, as it may pertain, assumes the exercise of options or warrants granted or held by such shareholder that are exercisable as of March 17, 2014.

FIVE PERCENT STOCKHOLDERS ⁸

Name and Address	Title	Number of Shares Beneficially Owned	Percent of Class
SSB Ventures LLC 123 Center Park Drive, Suite 104 Knoxville, TN 37922	Stockholder	16,376,321	26.9%
Dolphin Offshore Partners, L.P. c/o Dolphin Mgmt. Services, Inc. P.O. Box 16867 Fernandina Beach, FL 32034	Stockholder	5,381,171	8.8%

⁸ Unless otherwise stated, all shares of Common Stock are directly held with sole voting and dispositive power. The shares set forth in the table are as of March 17, 2014.

⁹ Unless otherwise stated, all shares of common stock are directly held with sole voting and dispositive power. The shares set forth in the table are as of March 17, 2014.

¹⁰ Calculated pursuant to Rule 13d-3(d) under the Securities Exchange Act of 1934 based upon 60,842,413 shares of common stock being outstanding as of March 17, 2014. Shares not outstanding that are subject to options or warrants exercisable by the holder thereof within 60 days of March 17, 2014 are deemed outstanding for the purposes of calculating the number and percentage owned by such stockholder, but not deemed outstanding for the purpose of calculating the percentage of any other person. Unless otherwise noted, all shares listed as beneficially owned by a stockholder are actually outstanding.

¹¹ Consists of 33,000 shares held directly and vested, fully exercisable options to purchase 125,000 shares.

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SECURITY OWNERSHIP OF DIRECTORS AND OFFICERS

Name and Address	Title	Number of Shares Beneficially Owned ⁹	Percent of Class ¹⁰
Matthew K. Behrent	Director	158,000 ¹¹	Less than 1%
Hughree F. Brooks	Director	75,000 ¹²	Less than 1%
Michael J. Rugen	Chief Financial Officer	320,000	Less than 1%
Peter E. Salas	Director; Chairman of the Board	21,182,492 ¹³	34.8%
Cary V. Sorensen	Vice President; General Counsel; Secretary	310,226 ¹⁴	Less than 1%
Richard M. Thon	Director	6,250 ¹⁵	Less than 1%
All Officers and Directors as a group		22,051,968 ¹⁶	36.2%

Change in Control

To the knowledge of the Company's management, there are no present arrangements or pledges of the Company's securities which may result in a change in control of the Company.

Equity Compensation Plan Information

The following table sets forth information regarding the Company's equity compensation plans as of December 31, 2013.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights(a)	Weighted-average exercise price of outstanding options, warrants and rights(b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders ¹⁷	870,250	\$ 0.59	2,304,118
Equity compensation plans not approved by security holders	-	-	-
Total	870,250	\$ 0.59	2,304,118

¹² Consists of vested, fully exercisable options to purchase 75,000 shares.

¹³ Consists of directly, vested, fully exercisable options to purchase 125,000 shares and 15,676,321 held directly by SSB Ventures LLC over which he has voting control and 5,381,171 shares held directly by Dolphin Offshore Partners, L.P. (“Dolphin”). Peter E. Salas is a member of SSB Ventures LLC and is the sole shareholder of and controlling person of Dolphin Management, Inc. which is the general partner of Dolphin.

¹⁴ Consists of 36,226 shares held directly and vested, fully exercisable options to purchase 74,000 shares and 200,000 shares held directly by SSB Ventures LLC over which he has voting control. Cary V. Sorensen is a member of SSB Ventures LLC.

¹⁵ Consists of vested, fully exercisable options to purchase 6,250 shares.

¹⁶ Consists of 69,226 shares held directly by directors and management, 15,876,321 held by SSB Ventures LLC, 5,381,171 shares held by Dolphin and vested, and fully exercisable options to purchase 725,250 shares.

¹⁷ Refers to Tengasco, Inc. Stock Incentive Plan (the “Plan”) which was adopted to provide an incentive to key employees, officers, directors and consultants of the Company and its present and future subsidiary corporations, and to offer an additional inducement in obtaining the services of such individuals. The Plan provides for the grant to employees of the Company of “Incentive Stock Options” within the meaning of Section 422 of the Internal Revenue Code of 1986, as amended, nonqualified stock options to outside Directors and consultants the Company and stock appreciation rights. The Plan was approved by the Company’s shareholders on June 26, 2001. Initially, the Plan provided for the issuance of a maximum of 1,000,000 shares of the Company’s \$.001 par value common stock. Thereafter, the Company’s Board of Directors adopted and the shareholders approved amendments to the Plan to increase the aggregate number of shares that may be issued under the Plan to 7,000,000 shares. The most recent amendment to the Plan increasing the number of shares that may be issued under the Plan by 3,500,000 shares and extending the Plan for another 10 years was approved by the Company Board of Directors on February 1, 2008 and approved by the Company’s shareholders at the Annual Meeting of Stockholders held June 2, 2008.

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

Certain Transactions

There have been no material transactions, series of similar transactions or currently proposed transactions entered into since the beginning of Fiscal 2012 and 2013, to which the Company or any of its subsidiaries was or is to be a party, in which the amount involved exceeds the lesser of \$120,000 or one percent of the average of the Company's total assets at year-end for its last two completed fiscal years in which any director or executive officer or any security holder who is known to the Company to own of record or beneficially more than 5% of the Company's common stock, or any member of the immediate family of any of the foregoing persons, had a material interest.

In this Report on Form 10-K for the year ended December 31, 2013, the Company describes three transactions of the type described above, that the Company entered into with Hoactzin Partners, L.P. ("Hoactzin") in 2007 that remained in existence in 2012 and 2013. As noted above in Item 1, Business, page 9, Peter E. Salas, the Chairman of the Board of Directors of the Company, is the controlling person of Hoactzin and the Company's largest shareholder. These three 2007 transactions between the Company and Hoactzin are described at the following page locations in this Report and in the attached Notes to Consolidated Financial Statements: (1) the Ten Well Program, see Item 1, Business, pages 9 and F-16; (2) the net profits agreement at the Methane Project, see Item 1, Business, pages 13 and F-16; and (3) the Management Agreement, see Item 1, Business, pages 13 and F-17.

The approximate dollar value of the amount of Hoactzin's interest in each of these three 2007 transactions during each of the years 2012 and 2013 was as follows: (1) Ten Well Program - \$661,000 in 2012; \$568,000 in 2013 (calculated as the total payments attributable to Hoactzin for its program interest); (2) Net Profits agreement at the Methane Project - \$0 in 2012; \$0 in 2013 (calculated as the amount of net profits payable to Hoactzin; the project generated no net profits as described in the agreement, and therefore no amount was paid to Hoactzin for net profits, in either 2012 or 2013); and (3) Management Agreement - \$110,000 in 2012; \$21,000 in 2013 (calculated as the amount payable by Hoactzin to the Company in reimbursement of one half of the salary and benefits of Patrick McInturff, as manager employed by the Company and excluding all vendor payables, bond premiums, and all other operating costs of Hoactzin's properties, all of which were paid at all times by Hoactzin and not by the Company, in the ordinary course of Hoactzin's ownership and not under the Management Agreement).

In addition to the three 2007 transactions, Hoactzin owns a drilling program interest in the Company's "6 Well Program" in Kansas, acquired in 2005 by Hoactzin in exchange for surrender of the Company's promissory notes given by the Company for borrowings to fund the redemption in 2004 of the Company's three series of preferred stock, all as previously disclosed. Hoactzin's interest in the 6 Well Program was \$49,000 in 2012; and \$45,000 in 2013 (calculated as the total payments attributable to Hoactzin for its program interest) and is expected to decrease in the future as the wells involved naturally decline in produced volumes.

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Director Independence

The Rules of the NYSE MKT (the “NYSE MKT Rules”) of which the Company is a member require that an issuer, such as the Company, which is a Smaller Reporting Company pursuant to Regulation S-K Item 10(f)(1), maintain a board of directors of which at least one-half of the members are independent in that they are not officers of the Company and are free of any relationship that would interfere with the exercise of their independent judgment. The NYSE MKT Rules also require that as a Smaller Reporting Company, the Company’s Board of Directors’ Audit Committee be comprised of at least two members all of whom qualify as independent under the criteria set forth in Rule 10 A-3 of the Securities Exchange Act of 1934 and NYSE MKT Rule 803(b)(2)(c). The Board of Directors has determined that the Company’s four directors, Matthew K. Behrent, Hughree F. Brooks, Richard M. Thon, and Peter E. Salas, are independent as defined by the NYSE MKT Rules, and that Matthew K. Behrent, Richard M. Thon, and Hughree F. Brooks are also independent as defined by Section 10A(m)(3) of the Securities Exchange Act of 1934 and the rules and regulations of the Securities and Exchange Commission; and that none of these directors have any relationship which would interfere with the exercise of his independent judgment in carrying out his responsibilities as a director. In reaching its determination, the Board of Directors reviewed certain categorical independence standards to provide assistance in the determination of director independence. The categorical standards are set forth below and provide that a director will not qualify as an independent director under the NYSE MKT Rules if:

The Director is, or has been during the last three years, an employee or an officer of the Company or any of its affiliates;

The Director has received, or has an immediate family member¹⁸ who has received, during any twelve consecutive months in the last three years any compensation from the Company in excess of \$120,000, other than compensation for service on the Board of Directors, compensation to an immediate family member who is an employee of the Company other than an executive officer, compensation received as an interim executive officer or benefits under a tax-qualified retirement plan, or non-discretionary compensation;

¹⁸ Under these categorical standards “immediate family member” includes a person’s spouse, parents, children, siblings, mother-in-law, father-in-law, brother-in-law, sister-in-law, son-in-law, daughter-in-law, and anyone who resides in such person’s home (other than a domestic employee).

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The Director is a member of the immediate family of an individual who is, or has been in any of the past three years, employed by the Company or any of its affiliates as an executive officer;

The Director, or an immediate family member, is a partner in, or controlling shareholder or an executive officer of, any for-profit business organization to which the Company made, or received, payments (other than those arising solely from investments in the Company's securities) that exceed 5% of the Company's or business organization's consolidated gross revenues for that year, or \$200,000, whichever is more, in any of the past three years;

The Director, or an immediate family member, is employed as an executive officer of another entity where at any time during the most recent three fiscal years any of the Company's executives serve on that entity's compensation committee; or

The Director, or an immediate family member, is a current partner of the Company's outside auditors, or was a partner or employee of the Company's outside auditors who worked on the Company's audit at any time during the past three years.

The following additional categorical standards were employed by the Board in determining whether a director qualified as independent to serve on the Audit Committee and provide that a director will not qualify if:

The Director directly or indirectly accepts any consulting, advisory, or other compensatory fee from the Company or any of its subsidiaries; or

The Director is an affiliated person¹⁹ of the Company or any of its subsidiaries.

The Director participated in the preparation of the Company's financial statements at any time during the past three years.

The independent members of the Board meet as often as necessary to fulfill their responsibilities, but meet at least annually in executive session without the presence of non-independent directors and management.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Audit and Non-Audit Fees

The following table presents the fees for professional audit services rendered by the Company's current independent accountants, Hein & Associates ("Hein"), for the audit of the Company's annual consolidated financial statements and fees for professional audit services rendered for the quarterly reviews for the fiscal years ended December 31, 2013 and December 31, 2012:

¹⁹ For purposes of this categorical standard, an "affiliated person of the Company" means a person that directly or indirectly through intermediaries controls, or is controlled by, or is under common control with the Company. A person will not be considered to be in control of the Company, and therefore not an affiliate of the Company, if he is not the beneficial owner, directly or indirectly of more than 10% of any class of voting securities of the Company and he is not an executive officer of the Company. Executive officers of an affiliate of the Company as well as a director who is also an employee of an affiliate of the Company will be deemed to be affiliates of the Company.

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AUDIT AND NON-AUDIT FEES

	2013	2012
Audit Fees	\$131,275	\$132,375
Audit-Related Fees	-	-
Tax Fees	-	-
All Other Fees	-	-
Total Fees	\$131,275	\$132,375

Audit fees include fees related to the services rendered in connection with the annual audit of the Company's consolidated financial statements, the quarterly reviews of the Company's quarterly reports on Form 10-Q and the reviews of and other services related to statutory filings or engagements for the subject fiscal years.

Audit-related fees are for assurance and related services by the principal accountants that are reasonably related to the performance of the audit or review of the Company's financial statements.

Tax Fees include services for (i) tax compliance, (ii) tax advice, (iii) tax planning and (iv) tax reporting.

All Other Fees includes fees for all other services provided by the principal accountants not covered in the other categories such as litigation support, etc.

All of the services for 2013 and 2012 were performed by the full-time, permanent employees of Hein.

All of the 2013 services described above were approved by the Audit Committee pursuant to the SEC rule that requires audit committee pre-approval of audit and non-audit services provided by the Company's independent auditors. The Audit Committee considered whether the provisions of such services, including non-audit services, by Hein were compatible with maintaining its independence and concluded they were.

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PART IV.

ITEM 15. EXHIBITS AND FINANCIAL STATEMENTS SCHEDULES

A. The following documents are filed as part of this Report:

1. Financial Statements:

Consolidated Balance Sheets

Consolidated Statements of Operations

Consolidated Statements of Stockholders Equity

Consolidated Statements of Cash Flows

Notes to Consolidated Financial Statements

2. Financial Schedules:

Schedules have been omitted because the information required to be set forth therein is not applicable or is included in the Consolidated Financial Statements or notes thereto.

3. Exhibits.

The following exhibits are filed with, or incorporated by reference into this Report:

Exhibit Index

<u>Exhibit Number</u>	<u>Description</u>
3.1	Delaware Certificate of Incorporation (Incorporated by reference to Exhibit B to registrant's Definitive Proxy Statement pursuant to Schedule 14a filed May 2, 2011).
3.2	Bylaws (Incorporated by reference to Exhibit B to registrant's Definitive Proxy Statement filed May 2, 2011).
3.3	Agreement and Plan of Merger of Tengasco, Inc. (a Tennessee corporation with and into Tengasco, Inc., a Delaware corporation dated as of April 15, 2011 (Incorporated by reference to Exhibit B to registrant's Definitive Proxy Statement pursuant to Schedule 14a filed May 2, 2011).
4.1	Form of Rights Certificate (Incorporated by reference to registrant's statement on Form S-1 filed February 13, 2004 Reg. File No. 333-109784).
10.1	Tengasco, Inc. Incentive Stock Plan (Incorporated by reference to Exhibit 4.1 to the registrant's registration statement on Form S-8 filed October 26, 2000).
10.2	Amendment to the Tengasco, Inc. Stock Incentive Plan dated May 19, 2005 (Incorporated by reference to Exhibit 4.2 to the registrant's registration statement on Form S-8 filed June 3, 2005).

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- 10.3 Loan and Security Agreement dated as of June 29, 2006 between Tengasco, Inc. and Citibank Texas, N.A. (Incorporated by reference to Exhibit 10.1 to the registrant's Current Report on Form 8-K dated June 29, 2006).
- 10.4 Subscription Agreement of Hoactzin Partners, L.P. for the Company's ten well drilling program on its Kansas Properties dated August 3, 2007 (Incorporated by reference to Exhibit 10.15 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2007 filed March 31, 2008 [the "2007 Form 10-K"]).
- 10.5 Agreement and Conveyance of Net Profits Interest dated September 17, 2007 between Manufactured Methane Corporation as Grantor and Hoactzin Partners, LP as Grantee (Incorporated by reference to Exhibit 10.16 to the 2007 Form 10-K).
- 10.6 Agreement for Conditional Option for Exchange of Net Profits Interest for Convertible Preferred Stock dated September 17, 2007 between Tengasco, Inc., as Grantor and Hoactzin Partners, L.P., as Grantee (Incorporated by reference to Exhibit 10.17 to the 2007 Form 10-K).
- 10.7 Assignment of Notes and Liens Dated December 17, 2007 between Citibank, N.A., as Assignor, Sovereign Bank, as Assignee and Tengasco, Inc., Tengasco Land & Mineral Corporation and Tengasco Pipeline Corporation as Debtors (Incorporated by reference to Exhibit 10.18 to the 2007 Form 10-K).
- 10.8 Management Agreement dated December 18, 2007 between Tengasco, Inc. and Hoactzin Partners, L.P. (Incorporated by reference to Exhibit 10.20 to the 2007 Form 10-K).
- 10.9 Amendment to the Tengasco, Inc. Stock Incentive Plan dated February 1, 2008, 2008 (Incorporated by reference to Exhibit 4.1 to the registrant's registration statement on Form S-8 filed June 3, 2008).
- 10.10 Assignment of Credit Facility to F&M Bank and Trust Company (Incorporated by reference to Exhibit 10.15 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2010 filed on March 31, 2011).
- 10.11 Ninth Amendment to Loan and Security Agreement dated February 22, 2011 between Tengasco, Inc. as borrower and F&M Bank & Trust Company as Lender (Incorporated by reference to Exhibit 9.01 to the registrant's Current Report on Form 8-K filed on February 25, 2011).
- 10.12 Tenth Amendment to Loan and Security Agreement dated March 14, 2012 between Tengasco, Inc. as borrower and F&M Bank & Trust Company as Lender. (Incorporated by reference to Exhibit 10.17 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2012 filed on March 29, 2013)
- 10.13 Eleventh Amendment to Loan and Security Agreement dated September 12, 2012 between Tengasco, Inc. as borrower and F&M Bank & Trust Company as Lender (Incorporated by reference to Exhibit 10.18 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2012 filed on March 29, 2013).

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10.14	Twelfth Amendment to Loan and Security Agreement dated January 29, 2013 between Tengasco, Inc. as borrower and F&M Bank & Trust Company as Lender (Incorporated by reference to Exhibit 10.19 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2012 filed on March 29, 2013).
10.15	Thirteenth Amendment to Loan and Security Agreement dated March 6, 2013 between Tengasco, Inc. as borrower and F&M Bank & Trust Company as Lender (Incorporated by reference to Exhibit 10.20 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2012 filed on March 29, 2013).
<u>10.16*</u>	Fourteenth Amendment to Loan and Security Agreement dated October 24, 2013 between Tengasco, Inc. as borrower and F&M Bank & Trust Company as Lender
<u>10.17*</u>	Fifteenth Amendment to Loan and Security Agreement dated March 17, 2014 between Tengasco, Inc. as borrower and F&M Bank & Trust Company as Lender
14	Code of Ethics (Incorporated by reference to Exhibit 14 to the registrant's Annual Report on Form 10-K filed March 30, 2004).
21	List of subsidiaries (Incorporated by reference to Exhibit 21 to the 2007 Form 10-K).
<u>23.1*</u>	Consent of LaRoche Petroleum Consultants, Ltd.
<u>31.1*</u>	Certification of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14
<u>31.2*</u>	Certification of Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a)
<u>32.1*</u>	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
<u>32.2*</u>	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
<u>99.1*</u>	Report of LaRoche Petroleum Consultants, Ltd. has been added to the filing for the year ended December, 31, 2013
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Definition Linkbase Document
101.LAB*	XBRL Taxonomy Label Linkbase Document
101.PRE*	XBRL Taxonomy Presentation Linkbase Document

* Exhibit filed with this Report

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SIGNATURES

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

Dated: March 31, 2014

Tengasco, Inc.

(Registrant)

By: s/ Michael J. Rugen

Michael J. Rugen,

Chief Executive Officer

Principal Financial and Accounting Officer

Pursuant to the requirements of the Securities and Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in their capacities and on the dates indicated.

Signature	Title	Date
<u>s/ Matthew K. Behrent</u> Matthew K. Behrent	Director	March 31, 2014
<u>s/ Hughree F. Brooks</u> Hughree F. Brooks	Director	March 31, 2014
<u>s/ Peter E. Salas</u> Peter E. Salas	Director	March 31, 2014
<u>s/ Richard M. Thon</u> Richard M. Thon	Director	March 31, 2014
<u>s/ Michael J. Rugen</u> Michael J. Rugen	Chief Executive Officer and Principal Financial Accounting Officer	March 31, 2014

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Tengasco, Inc.
and Subsidiaries

Consolidated Financial Statements

Years Ended December 31, 2013, 2012, and 2011

Report of Independent Registered Public Accounting Firms F-2

Consolidated Financial Statements

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Consolidated Statements of Stockholders' Equity F-6

Consolidated Statements of Cash Flows F-7

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Tengasco, Inc.

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

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

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

/s/ Hein & Associates LLP

Houston, Texas
March 31, 2014

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Tengasco, Inc. and Subsidiaries

Consolidated Balance Sheets

(In thousands, except per share and share data)

	December 31,	
	2013	2012
Assets		
Current		
Cash and cash equivalents	\$54	\$31
Accounts receivable, less allowance for doubtful accounts of \$14 and \$0	1,285	1,608
Accounts receivable-related party, less allowance for doubtful accounts of \$159 and \$257	168	68
Inventory	1,253	1,402
Deferred tax asset - current	130	-
Other current assets	312	194
Total current assets	3,202	3,303
Restricted cash	507	507
Loan fees, net	35	57
Oil and gas properties, net (full cost accounting method)	24,123	24,700
Methane project, net	4,389	4,445
Other property and equipment, net	247	321
Assets held for sale	-	1,400
Deferred tax asset - noncurrent	7,209	9,434
Total assets	\$39,712	\$44,167

See accompanying Notes to Consolidated Financial Statements

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Tengasco, Inc. and Subsidiaries

Consolidated Balance Sheets

(In thousands, except per share and share data)

	December 31,	
	2013	2012
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable – trade	\$367	\$648
Accounts payable – other	327	325
Accounts payable – related party	412	-
Accrued liabilities	444	615
Current maturities of long-term debt	82	100
Total current liabilities	1,632	1,688
Asset retirement obligation	1,780	2,099
Long term debt, less current maturities	3,375	10,246
Total liabilities	6,787	14,033
Commitments and contingencies (Note 9)		
Stockholders' equity		
Common stock, \$.001 par value: authorized 100,000,000 Shares; 60,842,413 shares issued and outstanding	61	61
Additional paid in capital	55,671	55,699
Accumulated deficit	(22,807)	(25,626)
Total stockholders' equity	32,925	30,134
Total liabilities and stockholders' equity	\$39,712	\$44,167

See accompanying Notes to Consolidated Financial Statements

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Tengasco, Inc. and Subsidiaries
 Consolidated Statements of Operations
 (In thousands, except per share and share data)

	Year ended December 31,			
	2013	2012	2011	
Revenues	\$15,700	\$20,557	\$17,062	
Cost and expenses				
Production costs and taxes	5,524	7,182	5,944	
Depreciation, depletion, and amortization	2,912	3,403	2,527	
General and administrative	2,059	2,613	2,324	
Total cost and expenses	10,495	13,198	10,795	
Income from operations	5,205	7,359	6,267	
Other income (expense)				
Net interest expense	(357) (743) (642)
(Loss) on derivatives	-	(142) (407)
Gain on sale of assets	118	83	37	
Total other (expense)	(239) (802) (1,012)
Income from continuing operations before income tax	4,966	6,557	5,255	
Deferred income tax expense	(1,915) (2,226) (245)
Current income tax expense	(95) (87) (44)
Net income from continuing operations	\$2,956	\$4,244	\$4,966	
(Loss) from discontinued operations, net of income tax benefit	\$(137) \$(4,311) \$(286)
Net income (loss)	\$2,819	\$(67) \$4,680	
Net income (loss) per share - Basic				
Net income from continuing operations	\$0.05	\$0.07	\$0.08	
Net income (loss) from discontinued operations	\$(0.00) \$(0.07) \$(0.00)
Net income (loss) per share - Diluted				
Net income from continuing operations	\$0.05	\$0.07	\$0.08	
Net income (loss) from discontinued operations	\$(0.00) \$(0.07) \$(0.00)
Shares used in computing earnings per share				
Basic	60,842,413	60,778,356	60,701,660	
Diluted	60,919,878	61,154,631	61,088,983	

See accompanying Notes to Consolidated Financial Statements
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Tengasco, Inc. and Subsidiaries

Consolidated Statements of Stockholders' Equity

(In thousands, except per share and share data)

	Common Stock		Paid-in Capital	Accumulated Deficit	Total
	Shares	Amount			
Balance, December 31, 2010	60,687,413	\$ 61	\$55,402	\$ (30,239)) \$25,224
Net income	-	-	-	4,680	4,680
Options and compensation expense	-	-	165	-	165
Common stock issued for exercise of options	50,000	-	28	-	28
Balance, December 31, 2011	60,737,413	\$ 61	\$55,595	\$ (25,559)) \$30,097
Net loss	-	-	-	(67)) (67)
Options and compensation expense	-	-	52	-	52
Common stock issued for exercise of options	105,000	-	52	-	52
Balance, December 31, 2012	60,842,413	\$ 61	\$55,699	\$ (25,626)) \$30,134
Net income	-	-	-	2,819	2,819
Options and compensation expense	-	-	(28)	-	(28)
Balance, December 31, 2013	60,842,413	\$ 61	\$55,671	\$ (22,807)) \$32,925

See accompanying Notes to Consolidated Financial Statements

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Table of contentsTengasco, Inc. and Subsidiaries
Consolidated Statements of Cash Flows
(In thousands)

	Year Ended December 31,		
	2013	2012	2011
Operating activities			
Net income from continuing operations	\$2,956	\$4,244	\$4,966
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, depletion, and amortization	2,912	3,403	2,527
Amortization of loan fees-interest expenses	32	55	77
Accretion of discount on asset retirement obligation	120	132	96
Gain on sale of vehicles/equipment	(118)	(83)	(37)
Compensation and services paid in stock options / equipment	50	52	165
Deferred income tax expense	1,915	2,226	245
Loss on derivatives	-	142	407
Allowance for doubtful accounts	(84)	257	-
Changes in assets and liabilities			
Restricted cash	-	(386)	-
Accounts receivable	307	(89)	666
Inventory and other assets	31	(694)	(283)
Accounts payable	103	196	(75)
Accrued liabilities	(184)	(95)	139
Settlement on asset retirement obligations	(69)	(52)	(165)
Net cash provided by operating activities – continuing operations	7,971	9,308	8,728
Net cash (used in) in operating activities – discontinued operations	(85)	(265)	(237)
Net cash provided by operating activities	7,886	9,043	8,491
Investing activities			
Net additions to oil and gas properties	(2,314)	(8,116)	(8,279)
Additions to Methane Project	(2)	(464)	(811)
Section 1603 refund – methane facilities	-	1,000	-
Additions to other property & equipment	(8)	(15)	(48)
Proceeds from sale of other property & equipment	106	22	-
Derivative costs and settlements	-	-	(1,236)
Net cash (used in) investing activities – continuing operations	(2,218)	(7,573)	(10,374)
Net cash provided by investing activities – discontinued operations	1,395	-	-
Net cash (used in) investing activities	(823)	(7,573)	(10,374)
Financing activities			
Proceeds from exercise of options/warrants	-	52	28
Payment in lieu of exercise of options/warrants	(60)	-	-
Proceeds from borrowings	7,946	18,339	17,912
Repayment of borrowings	(13,606)	(20,133)	(16,307)
Loan fees	(10)	(30)	(60)
Net cash provided by (used in) financing activities – continuing operations	(5,730)	(1,772)	1,573
Net cash provided by (used in) financing activities – discontinued operations	(1,310)	265	237
Net cash provided by (used in) financing activities	(7,040)	(1,507)	1,810
Net change in cash and cash equivalents – continuing operations	23	(37)	(73)
Cash and cash equivalents, beginning of period	31	68	141

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Cash and cash equivalents, end of period	\$54	\$31	\$68
Supplemental cash flow information:			
Cash interest payments	\$325	\$688	\$565
Cash paid for taxes	\$38	\$67	\$8
Supplemental non-cash investing and financing activities:			
Financed company vehicles	\$188	\$175	\$262
Asset retirement obligations incurred	\$26	\$92	\$559
Revisions to asset retirement obligations	\$(48) \$-	\$502
Capital expenditures included in accounts payable and accrued liabilities	\$175	\$-	\$691

See accompanying Notes to Consolidated Financial Statements

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Tengasco, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

1. Description of Business and Significant Accounting Policies

Tengasco, Inc. is a Delaware corporation (the “Company”). The Company is in the business of exploration for and production of oil and natural gas. The Company’s primary area of oil exploration and production is in Kansas. The Company’s primary area of natural gas exploration and production has been the Swan Creek Field in Tennessee. The Company sold all of its oil and gas leases and producing assets in Tennessee on August 16, 2013.

The Company’s wholly-owned subsidiary, Tengasco Pipeline Corporation (“TPC”), owned and operated a 65 mile intrastate pipeline which it constructed to transport natural gas from the Company’s Swan Creek Field to customers in Kingsport, Tennessee. As the Company had entered into an agreement to sell the pipeline asset, it had been classified as “Assets held for sale” in the Consolidated Balance Sheet as of December 31, 2012 and the related results of operations have been classified as “(Loss) from discontinued operations, net of income tax benefit” in the Consolidated Statement of Operations for the years ended December 31, 2013, 2012, and 2011. The Company sold of all its pipeline related assets on August 16, 2013. (See Note 7. Assets Held for Sale and Discontinued Operations)

The Company’s wholly-owned subsidiary, Manufactured Methane Corporation (“MMC”) operates treatment and delivery facilities for the extraction of methane gas from nonconventional sources for eventual sale to natural gas and electricity customers.

Principles of Consolidation

The accompanying consolidated financial statements are presented in accordance with accounting principles generally accepted in the United States (“U.S. GAAP”). The consolidated financial statements include the accounts of the Company, and its wholly-owned subsidiaries after elimination of all significant intercompany transactions and balances.

Use of Estimates

The accompanying consolidated financial statements are prepared in conformity with U.S. GAAP which require management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the dates of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Significant estimates include reserve quantities and estimated future cash flows associated with proved reserves, which significantly impact depletion expense and potential impairments of oil and natural gas properties, income taxes and the valuation of deferred tax assets, stock-based compensation and commitments and contingencies. We analyze our estimates based on historical experience and various other assumptions that we believe to be reasonable. While we believe that our estimates and assumptions used in preparation of the consolidated financial statements are appropriate, actual results could differ from those estimates.

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Tengasco, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

Revenue Recognition

Revenues are recognized based on actual volumes of oil, natural gas, methane gas, and electricity sold to purchasers at a fixed or determinable price, when delivery has occurred and title has transferred, and collectability is reasonably assured. Crude oil is stored and at the time of delivery to the purchasers, revenues are recognized. Natural gas meters are placed at the customer's location and usage is billed each month. There were no material natural gas imbalances at December 31, 2013 or 2012. Methane gas and electricity sales meters are located at the Carter Valley landfill site and sales of methane and electricity are billed each month.

Cash and Cash Equivalents

Cash and cash equivalents include temporary cash investments with a maturity of ninety days or less at date of purchase. The Company has elected to enter into a sweep account arrangement allowing excess cash balances to be used to temporarily pay down the credit facility, thereby, reducing overall interest cost.

Restricted Cash

As security required by Tennessee oil and gas regulations, the Company placed \$120,500 in a Certificate of Deposit to cover future asset retirement obligations for the Company's Tennessee wells. At December 31, 2013 and 2012, this amount was recorded in the Consolidated Balance Sheets under "Restricted cash".

In addition, during the 4th quarter of 2012, the Company placed \$386,000 as collateral for a bond to appeal a civil penalty related to issuance of an "Incidence of Non-Compliance" by the Bureau of Ocean Energy Management ("BOEM") concerning one of the Hoactzin wells operated by the Company pursuant to the Management Agreement. At December 31, 2013 and 2012, this amount was recorded in the Consolidated Balance Sheets under "Restricted cash".

Inventory

Inventory consists of crude oil in tanks and is carried at lower of cost or market value. The cost component of the oil inventory is calculated using the average per barrel cost which includes production costs and taxes, allocated general and administrative costs, and allocated interest cost. The market component is calculated using the average December oil sales price for the Company's Kansas properties. In addition, the Company also carried equipment and materials to be used in its Kansas operation and is carried at the lower of cost or market value. The cost component of the equipment and materials inventory represents the original cost paid for the equipment and materials. The market component is based on estimated sales value for similar equipment and materials at the end of each year. At December 31, 2013 and 2012, inventory consisted of the following (in thousands):

	December 31,	
	2013	2012
Oil – carried at cost	\$765	\$650
Equipment and materials – carried at cost	488	752
Total inventory	\$1,253	\$1,402

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Tengasco, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

Oil and Gas Properties

The Company follows the full cost method of accounting for oil and gas property acquisition, exploration, and development activities. Under this method, all costs incurred in connection with acquisition, exploration, and development of oil and gas reserves are capitalized. Capitalized costs include lease acquisitions, seismic related costs, certain internal exploration costs, drilling, completion, and estimated asset retirement costs. The capitalized costs of oil and gas properties, plus estimated future development costs relating to proved reserves and estimated asset retirement costs which are not already included net of estimated salvage value, are amortized on the unit-of-production method based on total proved reserves. The Company has determined its reserves based upon reserve reports provided by LaRoche Petroleum Consultants Ltd. since 2009. The costs of unproved properties are excluded from amortization until the properties are evaluated, subject to an annual assessment of whether impairment has occurred. The Company had \$736,000 and \$457,000 in unevaluated properties as of December 31, 2013 and 2012, respectively. Proceeds from the sale of oil and gas properties are accounted for as reductions to capitalized costs unless such sales cause a significant change in the relationship between costs and the estimated value of proved reserves, in which case a gain or loss is recognized.

At the end of each reporting period, the Company performs a “ceiling test” on the value of the net capitalized cost of oil and gas properties. This test compares the net capitalized cost (capitalized cost of oil and gas properties, net of accumulated depreciation, depletion and amortization and related deferred income taxes) to the present value of estimated future net revenues from oil and gas properties using an average price (arithmetic average of the beginning of month prices for the prior 12 months) and current cost discounted at 10% plus cost of properties not being amortized and the lower of cost or estimated fair value of unproven properties included in the cost being amortized (ceiling). If the net capitalized cost is greater than the ceiling, a write-down or impairment is required. A write-down of the carrying value of the asset is a non-cash charge that reduces earnings in the current period. Once incurred, a write-down may not be reversed in a later period.

Asset Retirement Obligation

An asset retirement obligation associated with the retirement of a tangible long-lived asset is recognized as a liability in the period incurred, with an associated increase in the carrying amount of the related long-lived asset, our oil and natural gas properties. The cost of the tangible asset, including the asset retirement cost, is depleted over the useful life of the asset. The asset retirement obligation is recorded at its estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligation discounted at our credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value. Accretion expense is recorded as “Production costs and taxes” in the Consolidated Statements of Operations. If the estimated future cost of the asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the long-lived asset. Revisions to estimated asset retirement obligations can result from changes in retirement cost estimates, revisions to estimated inflation rates, and changes in the estimated timing of abandonment.

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Tengasco, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

Manufactured Methane Facilities

The methane facilities were placed into service on April 1, 2009. The methane facilities are being depreciated over an estimated useful life of 32 years and 9 months beginning at the time it was placed in service. This useful life is based on the estimated landfill closure date of December 2041.

In June 2012, the Company received a payment in the amount of approximately \$1.0 million from the United States Department of the Treasury for a cash payment in lieu of tax credits relating to the methane facilities. The payment to the Company was authorized under Section 1603 of Division B of the American Recovery and Reinvestment Act of 2009. The grant amount was calculated pursuant to provisions applicable to a "landfill gas project," defined in this statute as a project generating electricity from landfill gas. The Company may not take investment tax credits for this facility as a result of accepting the cash payment, and is subject to annual reporting of the status of the project and recapture of all or a portion of the payment in the event the project were to be assigned to an ineligible nonprofit or governmental entity, during the five year period following the date of the award. The Company does not anticipate that the payment will be subject to recapture. Pursuant to the terms of the implementing federal regulations, the cash payment awarded is not treated as taxable income, but does reduce the taxable basis of the project by half of the grant amount. However, the book carrying amount of the property was reduced by the full amount of the payment.

Other Property and Equipment

Other property and equipment is carried at cost. The Company provides for depreciation of other property and equipment using the straight-line method over the estimated useful lives of the assets which range from two to seven years. Net gains or losses on other property and equipment disposed of are included in operating income in the period in which the transaction occurs.

Stock-Based Compensation

The Company records stock-based compensation to employees based on the estimated fair value of the award at grant date. We recognize expense on a straight line basis over the requisite service period. For stock-based compensation that vests immediately, the Company recognizes the entire expense in the quarter in which the stock-based compensation is granted. The Company recorded compensation expense of \$(28,000) in 2013, \$52,000 in 2012 and \$165,000 in 2011. Compensation expense in 2013 was impacted by a reversal of \$59,500 previously recognized as compensation expense.

Accounts Receivable

Accounts receivable consist of uncollateralized joint interest owner obligations due within 30 days of the invoice date, uncollateralized accrued revenues due under normal trade terms, generally requiring payment within 30 days of production, and other miscellaneous receivables. No interest is charged on past-due balances. Payments made on accounts receivable are applied to the earliest unpaid items. We review accounts receivable periodically and reduce the carrying amount by a valuation allowance that reflects our best estimate of the amount that may not be collectible. An allowance was recorded at December 31, 2013, but no such allowance was considered necessary at December 31, 2012. At December 31, 2013 and 2012, accounts receivable consisted of the following (in thousands):

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	December 31,	
	2013	2012
Revenue	\$1,179	\$1,517
Joint interest	35	65
Other	85	26
Allowance for doubtful accounts	(14)	-
Total accounts receivable	\$1,285	\$1,608

Income Taxes

Income taxes are reported in accordance with U.S. GAAP, which requires the establishment of deferred tax accounts for all temporary differences between the financial reporting and tax bases of assets and liabilities, using currently enacted federal and state income tax rates. In addition, deferred tax accounts must be adjusted to reflect new rates if enacted into law.

At December 31, 2013, federal net operating loss carryforwards amounted to approximately \$19.7 million which expire between 2019 and 2031. The total deferred tax asset was \$7.3 million and \$9.4 million at December 31, 2013 and 2012, respectively.

Realization of deferred tax assets is contingent on the generation of future taxable income. As a result, management considers whether it is more likely than not that all or a portion of such assets will be realized during periods when they are available, and if not, management provides a valuation allowance for amounts not likely to be recognized.

Management periodically evaluates tax reporting methods to determine if any uncertain tax positions exist that would require the establishment of a loss contingency. A loss contingency would be recognized if it were probable that a liability has been incurred as of the date of the financial statements and the amount of the loss can be reasonably estimated.

The amount recognized is subject to estimates and management's judgment with respect to the likely outcome of each uncertain tax position. The amount that is ultimately incurred for an individual uncertain tax position or for all uncertain tax positions in the aggregate could differ from the amount recognized.

Although management considers our valuation allowance as of December 31, 2013 and 2012 adequate, material changes in these amounts may occur in the future based on tax audits and changes in legislation.

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Concentration of Credit Risk

Financial instruments which potentially subject the Company to concentrations of credit risk consist principally of cash and accounts receivable. Cash and cash equivalents are maintained at financial institutions and, at times, balances may exceed federally insured limits. We have never experienced any losses related to these balances.

The Company's primary business activities include oil and gas sales to a limited number of customers in the states of Kansas and Tennessee. The related trade receivables subject the Company to a concentration of credit risk.

The Company sells a majority of its crude oil primarily to two customers in Kansas. Additionally, the Company presently sells all gas from the Methane Facility to one customer. In addition, the Company sells the electricity generated at the Carter Valley landfill site to a local utility. Although management believes that customers could be replaced in the ordinary course of business, if the present customers were to discontinue business with the Company, it may have a significant adverse effect on the Company's projected results of operations.

Revenue from the top three purchasers accounted for 79.8%, 14.9%, and 1.7% of total revenues for year ended December 31, 2013. Revenue from the top three purchasers accounted for 79.9%, 14.3% and 2.2% of total revenues for the year ended December 31, 2012. Revenue from the top three purchasers accounted for 82.5%, 14.5% and 2.0% of total revenues for the year ended December 31, 2011. As of December 31, 2013 and 2012, two of our oil purchasers accounted for 92.6% and 85.3%, respectively of our accounts receivable, of which one oil purchaser accounted for 80.7% and 71.9%, respectively.

Earnings per Common Share

We report basic earnings per common share, which excludes the effect of potentially dilutive securities, and diluted earnings per common share which include the effect of all potentially dilutive securities unless their impact is anti-dilutive. The following are reconciliations of the numerators and denominators of our basic and diluted earnings per share, (in thousands except for share and per share amounts):

	For the years ended December 31,		
	2013	2012	2011
Income (numerator):			
Net income from continuing operations	\$2,956	\$4,244	\$4,966
Net loss from discontinued operations	\$(137) \$(4,311) \$(286
Weighted average shares (denominator):			
Weighted average shares - basic	60,842,413	60,778,356	60,701,660
Dilution effect of share-based compensation, treasury method	77,465	376,275	387,233
Weighted average shares - dilutive	60,919,878	61,154,631	61,088,983
Earnings (loss) per share – Basic and Dilutive:			
Continuing Operations	\$0.05	\$0.07	\$0.08
Discontinued Operations	\$(0.00) \$(0.07) \$(0.00

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Fair Value of Financial Instruments

The carrying amounts of financial instruments including cash and cash equivalents, accounts receivable, accounts payables, accrued liabilities and long term debt approximates fair value as of December 31, 2013 and 2012.

Derivative Financial Instruments

The Company uses derivative instruments to manage our exposure to commodity price risk on sales of oil production. The Company does not enter into derivative instruments for speculative trading purposes. The Company presents the fair value of derivative contracts on a net basis where the right to offset is provided for in our counterparty agreements. As of December 31, 2013 and 2012, the Company did not have any open derivatives.

Reclassifications

Certain prior year amounts have been reclassified to conform to current year presentation with no effect on net income.

Discontinued Operations

During 2012, the Company committed to a plan to sell the Swan Creek and Pipeline assets. On March 1, 2013, the Company entered into an agreement to sell the Company's Swan Creek and Pipeline assets for \$1.5 million. Closing of this transaction occurred on August 16, 2013. The Company elected to classify the Pipeline assets as "Assets held for sale" in the Consolidated Balance Sheet as of December 31, 2012. The related results of operations have been classified as "(Loss) from discontinued operations, net of income tax benefit" in the Consolidated Statements of Operations for the years ended December 31, 2013, 2012, and 2011. The related cash flows have been classified as "Net cash (used in) operating activities – discontinued operations", "Net cash (used in) investing activities – discontinued operations", and Net cash (used in) financing activities – discontinued operations".

As the Swan Creek oil and gas assets represented only a small portion of the Company's full cost pool, these assets remained in oil and gas properties and the gain or loss on the sale was recorded against the full cost pool. Until these properties were sold in August 2013, the related operations were classified in continuing operations. (See Note 7. Assets Held for Sale and Discontinued Operations)

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2. Recent Accounting Pronouncements

In July 2013, the FASB issued ASU 2013-11 Income Taxes (Topic 740), Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists. This guidance provides that an unrecognized tax benefit, or a portion thereof, should be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward, except to the extent that a net operating loss carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date to settle any additional income taxes that would result from disallowance of a tax position, or the tax law does not require the entity to use, and the entity does not intend to use, the deferred tax asset for such purpose, then the unrecognized tax benefit should be presented as a liability. This guidance is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. Early adoption and retrospective application is permitted. The Company does not expect this to impact its operating results, financial position, or cash flows.

3. Related Party Transactions

On September 17, 2007, the Company entered into a drilling program with Hoactzin Partners, L.P. ("Hoactzin") for ten wells consisting of approximately three wildcat wells and seven developmental wells to be drilled on the Company's Kansas Properties (the "Ten Well Program"). Peter E. Salas, the Chairman of the Board of Directors of the Company, is the controlling person of Hoactzin. He was also at the time the sole shareholder and controlling person of Dolphin Management, Inc., the general partner of Dolphin Offshore Partners, L.P., which was the Company's largest shareholder at that time.

Under the terms of the Ten Well Program, Hoactzin paid the Company \$0.4 million for each well drilled in the Ten Well Program completed as a producing well and \$0.25 million for each well that was non-productive. The terms of the Ten Well Program also provide that Hoactzin would receive all the working interest in the ten wells in the Program, but would pay an initial fee to the Company of 25% of its working interest revenues net of operating expenses. This is referred to as a management fee but, as defined, is in the nature of a net profits interest. The fee paid to the Company by Hoactzin would increase to 85% when and if net revenues received by Hoactzin reach an agreed payout point of approximately 1.35 times Hoactzin's purchase price (the "Payout Point") for its interest in the Ten Well Program.

In March 2008, the Company drilled and completed the tenth and final well in the Ten Well Program. Of the ten wells drilled, nine were completed as oil producers and are currently producing approximately 32 barrels per day in total. Hoactzin paid a total of \$3.85 million (the "Purchase Price") for its interest in the Ten Well Program resulting in the Payout Point being determined as \$5.2 million.

Under the terms of the Company's agreement with Hoactzin, reaching the Payout Point may be accelerated by operation of a second agreement by which Hoactzin would apply 75% of the net profits it may receive from a methane extraction project discussed below developed by the Company's wholly-owned subsidiary, Manufactured Methane Corporation ("MMC"), to reaching the Payout Point.

On September 17, 2007, Hoactzin, simultaneously with subscribing to participate in the Ten Well Program, pursuant to the second agreement referred to above was conveyed a 75% net profits interest in the methane extraction project developed by MMC at the Carter Valley landfill owned by Republic Services in Church Hill, Tennessee (the "Methane Project"). Net profits, if any, from the Methane Project received by Hoactzin would be applied towards the determination of the Payout Point (as defined above) for the Ten Well Program.

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Through December 31, 2013, no payments have been made to Hoactzin for its 75% net profits interest in the Methane Project, because no net profits were generated.

The method of calculation of the net profits interest takes into account specific costs and expenses as well as gross gas revenues for the Methane Project. As a result of the startup costs and ongoing operating expenses, no net profits, as defined in the agreement, have been generated from startup in April, 2009 through December 31, 2013 for payment to Hoactzin under the net profits interest conveyed. When the Payout Point was reached from either the revenues from the wells drilled in the Ten Well Program or Hoactzin's share of the net profits from the Methane Project or a combination thereof, Hoactzin's net profits interest in the Methane Project was to decrease to a 7.5% net profits interest.

As of December 31, 2013, net revenues received by Hoactzin from the Ten Well Program totaled \$5.15 million which left a balance of \$51,000 until the Payout Point.

On December 18, 2007, the Company entered into a Management Agreement with Hoactzin to manage on behalf of Hoactzin all of its working interest in certain oil and gas properties owned by Hoactzin and located in the onshore Texas Gulf Coast, and offshore Texas and offshore Louisiana.

As part of the consideration for the Company's agreement to enter into the Management Agreement, Hoactzin granted to the Company an option to participate in up to a 15% working interest on a dollar for dollar cost basis in any new drilling or workover activities undertaken on Hoactzin's managed properties during the term of the Management Agreement. The term of the Management Agreement was stated to terminate on the earlier of the date Hoactzin sold its interest in its managed properties, or five years from the effective date. The Management Agreement terminated by its own terms on December 18, 2012. As of the date of this Report, the Company is assisting Hoactzin with becoming operator of record of these wells and transferring all corresponding bonding liability to Hoactzin. The Company has entered into a transition agreement with Hoactzin whereby Hoactzin and its controlling member indemnify the Company for any costs or liabilities incurred by the Company resulting from such assistance, or the fact that the Company is still the operator of record on certain of these wells.

During the course of the Management Agreement, the Company became the operator of certain properties owned by Hoactzin. The Company obtained from IndemCo, over time, bonds in the face amount of approximately \$10.7 million for the purpose of covering plugging and abandonment obligations for Hoactzin's operated properties located in federal offshore waters in favor of the Bureau of Ocean Energy Management ("BOEM"), as well as certain private parties. In connection with the issuance of these bonds the Company signed a Payment and Indemnity Agreement with IndemCo whereby the Company guaranteed payment of any bonding liabilities incurred by IndemCo. Dolphin Direct Equity Partners, LP also signed the Payment and Indemnity Agreement, thereby becoming jointly and severally liable with the Company for the obligations to IndemCo. Hoactzin has provided \$6.6 million in cash to IndemCo as collateral for these potential obligations. Dolphin Direct Equity Partners is a private equity fund controlled by Peter E. Salas that has a significant economic interest in Hoactzin. During 2012 and 2013, approximately \$4.6 million of these bonds were terminated which leaves a balance on the remaining IndemCo bonds of approximately \$6.1 million at December 31, 2013, an amount less than the \$6.6 million in existing collateral supplied by parties other than the Company.

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As part of the transition process, Hoactzin has secured new bonds from Argonaut Insurance Company to replace the IndemCo bonds. Also as part of the transition process, right-of-use and easement (“RUE”) bonds in the amount of \$1.55 million were issued by Argonaut in the Company’s name. Hoactzin is in the process of transferring these RUE bonds from the Company to Hoactzin. Hoactzin and Dolphin Direct signed an indemnity agreement with Argonaut as well as provided full collateral for the new Argonaut bonds, including the RUE bonds issued in the Company’s name. The Company is not party to the indemnity agreement with Argonaut and has not provided any collateral for the bonds issued.

As operator, the Company routinely contracted in its name for goods and services with vendors in connection with its operation of the Hoactzin properties. In practice, Hoactzin directly paid these invoices for goods and services that were contracted in the Company’s name. During late 2009 and early 2010, Hoactzin undertook several significant operations, for which the Company contracted in the ordinary course. As a result of the operations performed in late 2009 and early 2010, Hoactzin had significant past due balances to several vendors, a portion of which were included on the Company’s balance sheet. Payables related to these past due and ongoing operations remained outstanding at the end of 2013 and 2012 in the amount of \$327,000 and \$325,000 respectively. The Company has recorded the Hoactzin-related payables and the corresponding receivable from Hoactzin as of December 31, 2013 and 2012 in its Consolidated Balance Sheets under “Accounts payable – other” and “Accounts receivable – related party”. Since the second quarter of 2012, Hoactzin had not made payments to reduce these past due balances. Based on these circumstances, the Company has elected to establish an allowance in the amount of \$159,000 and \$257,000 for the balances outstanding at December 31, 2013 and 2012, respectively. This allowance was recorded in the Company’s Consolidated Balance Sheets under “Accounts receivable – related party” and in its Consolidated Statements of Operations in “General and administrative”.

The Company has entered into an agreement with Hoactzin whereby Hoactzin and Dolphin Direct are indemnifying the Company for any costs or liabilities incurred by the Company resulting from such assistance, or the fact that the Company is still the operator of record on certain of these wells. Until such time as Hoactzin becomes operator of record on these wells and the corresponding bonding liability is transferred from the Company to Hoactzin, per the transition agreement, the Company is suspending drilling payments to Hoactzin. As of December 31, 2013, the Company has suspended \$412,000 in payments. This balance of these suspended payments is recorded in the Consolidated Balance Sheet under “Accounts payable – related party”.

The Company has not advanced any funds to pay any obligations of Hoactzin. No borrowing capability of the Company has been used by the Company in connection with its obligations under the Management Agreement, except for those funds used to collateralize the appeal bond with RLI Insurance Company (see Note 9 Commitments and Contingencies).

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4. Oil and Gas Properties

The following table sets forth information concerning the Company's oil and gas properties: (in thousands):

	December 31,	
	2013	2012
Oil and gas properties, at cost	\$45,101	\$43,351
Unevaluated properties	736	457
Accumulated depreciation, depletion and amortization	(21,714)	(19,108)
Oil and gas properties, net	\$24,123	\$24,700

During the years ended December 31, 2013, 2012, and 2011, the Company recorded depletion expense of \$2.6 million, \$3.0 million and \$2.2 million, respectively.

5. Methane Project

The following table sets forth information concerning the Company's methane project: (in thousands):

	December 31,	
	2013	2012
Methane project, at cost	\$4,945	\$4,865
Accumulated depreciation	(556)	(420)
Methane project, net	\$4,389	\$4,445

During each of the years ended December 31, 2013, 2012, and 2011, the Company recorded depreciation expense of \$136,000, \$101,000, and \$103,000, respectively. In June 2012, the Company received a payment in the amount of approximately \$1.0 million from the United States Department of the Treasury for a cash payment in lieu of tax credits relating to the methane facilities. The payment to the Company was authorized under Section 1603 of Division B of the American Recovery and Reinvestment Act of 2009. This payment reduced the carrying amount of the Methane Project.

6. Other Property and Equipment

Other property and equipment consisted of the following as of December 31, 2013: (in thousands)

Type	Depreciable Life	Gross Cost	Accumulated Depreciation	Net Book Value
Machinery and equipment	5-7 yrs	\$20	\$ 13	\$ 7
Vehicles	2-5 yrs	475	235	240
Other	5 yrs	63	63	-
Total		\$558	\$ 311	\$ 247

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Other property and equipment consisted of the following as of December 31, 2012: (in thousands)

Type	Depreciable Life	Gross Cost	Accumulated Depreciation	Net Book Value
Machinery and equipment	5-7 yrs	\$978	\$ 878	\$ 100
Vehicles	2-5 yrs	772	551	221
Other	5 yrs	63	63	-
Total		\$1,813	\$ 1,492	\$ 321

The Company uses the straight-line method of depreciation for other property and equipment. During each of the years ended December 31, 2013, 2012, and 2011, the Company recorded depreciation expense of \$170,000, \$258,000, and \$229,000, respectively.

7. Assets Held For Sale and Discontinued Operations

Assets held for sale represent the carrying value of the pipeline asset of \$1.4 million at December 31, 2012. The pipeline asset was sold in August 2013, and therefore was not included in the balance sheet at December 31, 2013. The determination of the pipeline value at December 31, 2012 was based on discussions and negotiations with a third party regarding the sale of the Pipeline asset.

The following table summarizes the amounts in net loss from discontinued operations, net of income tax presented in the consolidated statement of Operations for the years ended December 31, 2013, 2012, and 2011 (in thousands):

	For the Years Ended		
	December 31,		
	2013	2012	2011
Revenues	\$22	\$30	\$23
Production costs and taxes	(164)	(315)	(260)
Depreciation, depletion, and amortization	-	(223)	(176)
Impairment	-	(5,242)	-
Gain on sale of assets	128	-	-
Deferred income tax benefit	(180)	1,419	127
Current income tax benefit	57	20	-
Net loss from discontinued operations, net of income tax	\$(137)	\$(4,311)	\$(286)

8. Long-Term Debt

Long-term debt consisted of the following: (in thousands)

December 31,	2013	2012
Note payable to revolving credit facility, with interest only payment until maturity.	\$3,257	\$10,138
Installment notes bearing interest at the rate of 5.5% to 8.25% per annum collateralized by vehicles with monthly payments including interest, insurance and maintenance of approximately \$20	200	208
Total long-term debt	3,457	10,346
Less current maturities	(82)	(100)

Long-term debt, less current maturities

\$3,375 \$10,246

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Future debt payments to unrelated entities as of December 31, 2013 consisted of the following: (in thousands)

	2014	2015	2016	Total
Bank Credit Facility	\$ -	\$ -	\$3,257	\$3,257
Company Vehicles	\$ 82	\$ 59	\$59	\$200
Total	\$ 82	\$ 59	\$3,316	\$3,457

At December 31, 2013, the Company had a revolving credit facility with F&M Bank & Trust Company (“F&M Bank”). Under the credit facility, loans and letters of credit are available to the Company on a revolving basis in an amount outstanding not to exceed the lesser of \$40 million or the Company’s borrowing base in effect from time to time. As of December 31, 2013, the Company’s borrowing base was \$17.5 million and the interest rate of prime plus 0.50% per annum. The Company’s interest rate at December 31, 2013 was 3.75%, and matures on January 27, 2016. The borrowing base remains subject to the existing periodic redetermination provision in the credit facility. The credit facility is secured by substantially all of the Company’s producing and non-producing oil and gas properties and the Company’s Methane Project and electric generation assets. The credit facility includes certain covenants with which the Company is required to comply. These covenants include leverage, interest coverage, minimum liquidity, and general and administrative coverage ratios. The Company is in compliance with all of the credit facility covenants.

On March 27, 2014, the Company’s senior credit facility with F&M Bank was amended to decrease the Company’s borrowing base from \$17.5 million to \$14.3 million and extend the term of the facility to January 27, 2016. The borrowing base remains subject to the existing periodic redetermination provisions in the credit facility. The interest rate remained prime plus 0.50% per annum. The maximum line of credit of the Company under the F&M Bank credit facility remained \$40 million.

The total borrowing by the Company under the F&M Bank facility at December 31, 2013 and December 31, 2012 was \$3.3 million and \$10.1 million, respectively. The next borrowing base review will take place in July 2014.

9. Commitments and Contingencies

The Company is a party to lawsuits in the ordinary course of its business. The Company does not believe that it is probable that the outcome of any individual action will have a material adverse effect, or that it is likely that adverse outcomes of individually insignificant actions will be significant enough, in number or magnitude, to have in the aggregate a material adverse effect on its financial statements.

On November 18, 2013, the Company entered into a month-to-month lease for office space in Knoxville, Tennessee. The payment on this lease is approximately \$6,000 per month. On December 15, 2013, the Company entered into a 38 month lease (2 months free) for office space in Denver Colorado. The payment on this lease is approximately \$2,700 per month and expires February 28, 2017. Future non-cancellable commitments related to this lease total approximately \$29,000 due in 2014, \$30,000 due in 2015, \$34,000 due in 2016, and \$6,000 due in 2017.

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Office rent expense for each of the three years ended December 31, 2013, 2012, and 2011 was \$92,000, \$80,000, and \$73,000, respectively.

The Company as designated operator was administratively issued an “Incidence of Non-Compliance” by BOEM concerning one of the Hoactzin wells subject to the Management Agreement. This action called for payment of a civil penalty of \$386,000 for the late filing of certain reports in 2011 by a contractor on the facility. The Company has filed an appeal of this action in order to attempt to significantly reduce the civil penalty. This appeal required a fully collateralized appeal bond to stay payment of the obligation until the appeal is determined. On November 1, 2012, the Company posted and collateralized this bond with RLI Insurance Company. If the bond was not posted, the appeal would have been administratively denied and the order to the Company as operator to pay the \$386,000 penalty would be final. While the Company believes it will ultimately prevail in the appeal process, it is reasonably possible to expect that the Company may be required to pay a portion of this penalty. The Company estimates the range of this possible payment to be between zero and \$386,000. As of December 31, 2013 and 2012, the Company has not accrued any liabilities associated with this penalty.

10. Fair Value Measurements

FASB ASC 820, “Fair Value Measurements and Disclosures”, establishes a framework for measuring fair value. That framework provides a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). The three levels of the fair value hierarchy under FASB ASC 820 are described as follows:

Level 1 – Observable inputs, such as unadjusted quoted prices in active markets, for substantially identical assets and liabilities.

Level 2 – Observable inputs other than quoted prices within Level 1 for similar assets and liabilities. These include quoted prices for similar assets and liabilities in active markets, quoted prices for identical assets and liabilities in markets that are not active, or other inputs that are observable or can be corroborated by observable market data. If the asset or liability has a specified or contractual term, the input must be observable for substantially the full term of the asset or liability.

Level 3 – Unobservable inputs that are supported by little or no market activity, generally requiring a significant amount of judgment by management. The assets or liabilities fair value measurement level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. Valuation techniques used need to maximize the use of observable inputs and minimize the use of unobservable inputs.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. Further, although the Company believes its valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date.

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Upon completion of wells, the Company records an asset retirement obligation at fair value using Level 3 assumptions.

Nonfinancial assets and liabilities are measured at fair value on a nonrecurring basis upon impairment. The following table sets forth by level, within the fair value hierarchy, the Company's assets and liabilities at fair value on a recurring basis as of December 31, 2012 (in thousands):

	Carrying Value Prior to Impairment	Level 1	Level 2	Level 3	Pre-Tax Non-Cash Impairment
Discontinued operations	\$ 6,642	\$ -	\$ -	\$ 1,400	\$ 5,242

Discontinued operations consisted of the Company's Pipeline asset. Fair value at December 31, 2012 was based on discussions and negotiations with a third party regarding the sale of the Pipeline asset. The Company's Pipeline asset was sold in August 2013; therefore no value was recorded for the asset on December 31, 2013.

The carrying amounts of other financial instruments including cash and cash equivalents, accounts receivable, account payables, accrued liabilities and long term debt in our balance sheet approximates fair value as of December 31, 2013 and December 31, 2012.

11. Asset Retirement Obligation

Our asset retirement obligations represent the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives in accordance with applicable laws. The following table summarizes the Company's Asset Retirement Obligation transactions for the years ended December 31, 2012 and 2013 (in thousands):

Balance December 31, 2011	\$ 1,927
Accretion expense	132
Liabilities incurred	92
Liabilities settled	(52)
Revision in estimated liabilities	-
Balance December 31, 2012	\$ 2,099
Accretion expense	120
Liabilities incurred	26
Liabilities settled	(417)
Revisions in estimated liabilities	(48)
Balance December 31, 2013	\$ 1,780

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The liabilities settled during 2013 also include removal of \$348,000 from the Asset Retirement Obligation related to the sale of the Tennessee oil and gas properties. The revisions in estimated liabilities in 2013 resulted primarily from change in timing of wells to be plugged.

12. Stock Options

In October 2000, the Company approved a Stock Incentive Plan which was effective for a ten-year period commencing on October 25, 2000 and ending on October 24, 2010. The aggregate number of shares of Common Stock as to which options and Stock Appreciation Rights may be granted to participants under the original Plan was not to exceed 7,000,000. The most recent amendment to the Plan increasing the number of shares that may be issued under the Plan by 3,500,000 shares and extending the Plan for another ten years was approved by the Company's Board of Directors on February 1, 2008 and approved by the Company's shareholders at the Annual Meeting of Stockholders held on June 2, 2008. Options are not transferable, are exercisable for 3 months after voluntary resignation from the Company, and terminate immediately upon involuntary termination from the Company. The purchase price of shares subject to this Plan shall be determined at the time the options are granted, but are not permitted to be less than 85% of the fair market value of such shares on the date of grant. Furthermore, a participant in the Plan may not, immediately prior to the grant of an Incentive Stock Option, own stock in the Company representing more than ten percent of the total voting power of all classes of stock of the Company unless the per share option price specified by the Board for the Incentive Stock Options granted such a participant is at least 110% of the fair market value of the Company's stock on the date of grant and such option, by its terms, is not exercisable after the expiration of 5 years from the date such stock option is granted.

Stock option activity in 2013, 2012, and 2011 is summarized below:

	2013		2012		2011	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding, beginning of year	1,372,250	\$ 0.61	1,471,000	\$ 0.61	1,571,000	\$ 0.60
Granted	75,000	\$ 0.54	87,500	\$ 0.85	186,745	\$ 1.01
Exercised	-	\$ 0.57	(105,000)	\$ 0.50	(50,000)	\$ 0.57
Expired/cancelled	(577,000)	\$ 0.72	(81,250)	\$ 1.12	(236,745)	\$ 0.82
Outstanding, end of year	870,250	\$ 0.59	1,372,250	\$ 0.61	1,471,000	\$ 0.61
Exercisable, end of year	790,250	\$ 0.60	1,212,250	\$ 0.62	1,231,000	\$ 0.63

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The following table summarizes information about stock options outstanding and exercisable at December 31, 2013:

Weighted Average Exercise Price	Options Outstanding (shares)	Weighted Average Remaining Contractual Life (years)	Options Exercisable (shares)
\$0.70	50,000	0.1	50,000
\$0.50	400,000	1.8	320,000
\$0.43	50,000	1.1	50,000
\$0.44	114,000	1.7	114,000
\$1.08	50,000	2.3	50,000
\$1.16	18,750	2.3	18,750
\$0.84	18,750	2.5	18,750
\$0.72	18,750	2.8	18,750
\$0.75	18,750	3.0	18,750
\$1.07	18,750	3.2	18,750
\$0.81	18,750	3.5	18,750
\$0.73	18,750	3.8	18,750
\$0.64	18,750	4.0	18,750
\$0.62	18,750	4.2	18,750
\$0.48	18,750	4.5	18,750
\$0.41	18,750	4.8	18,750
	870,250		790,250

During 2013, the Company issued the following options to each of the non-executive directors that remain outstanding as of December 31, 2013. These options vested upon grant date.

Options Issued to Each Non-executive Director	Total Options Issued to Non-executive Directors	Exercise Price	Grant Date	Expiration Date
6,250	18,750	\$ 0.64	1/2/2013	1/1/2018
6,250	18,750	\$ 0.62	4/1/2013	3/31/2018
6,250	18,750	\$ 0.48	7/1/2013	6/30/2018
6,250	18,750	\$ 0.41	10/2/2013	10/1/2018

The weighted average fair value per share of options granted in 2013 was \$0.25 and 2012 was \$0.47 calculated using the Black Scholes option pricing model.

Compensation expense related to stock options was \$(28,000) in 2013 and was \$51,000 in 2012 and \$165,000 in 2011. The 2013 amount was comprised of \$32,000 of current year compensation expense offset by reversal of \$59,500 previously recognized as compensation expense. This expense is recorded in "General and administrative" in the Consolidated Statements of Operations. At December 31, 2013, there was approximately \$9,000 of total unrecognized compensation costs related to unvested options that is expected to be recognized over a weighted average period of approximately 0.5 years. The fair value of stock options used to compute share based compensation is the estimated present value at grant date using the Black Scholes option pricing model with weighted average

assumptions for 2013 of expected volatility of 47.6%, a risk free interest rate of 2.97% and an expected option life remaining from 0.1 to 4.8 years. The weighted average assumptions for 2012 were expected volatility of 65.0%, a risk free interest rate of 2.71% and an expected option life remaining from 0.1 to 4.8 years. The weighted average assumptions used for 2011 were expected volatility of 59.3%, a risk fee interest rate of 3.64% and an expected option life remaining for 1.1 years to 4.8 years.

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On January 3, 2014, options to purchase 25,000 common shares at \$0.41 per share were issued to the Company's non-executive directors. These options fully vested upon grant date and will expire on January 2, 2019.

13. Income Taxes

The Company had taxable income for the years ended December 31, 2013 and 2012, but had no taxable income for the year ended December 31, 2011.

A reconciliation of the statutory U.S. Federal income tax and the income tax provision included in the accompanying consolidated statements of operations is as follows (in thousands):

Year Ended December 31, 2013	Continuing		Discontinued		Total	
	Operations	%	Operations	%	Operations	%
Statutory rate	34	%	34	%	34	%
Tax (benefit) expense at statutory rate	\$ 1,689		\$ (5)	\$ 1,684	
State income tax (benefit) expense	255		-		255	
Permanent difference	4		-		4	
Other	62		(62)	-	
Net change in deferred tax asset valuation allowance	-		190		190	
Total income tax provision (benefit)	\$ 2,010		\$ 123		\$ 2,133	

Year Ended December 31, 2012	Continuing		Discontinued		Total	
	Operations	%	Operations	%	Operations	%
Statutory rate	34	%	34	%	34	%
Tax (benefit) expense at statutory rate	\$ 2,229		\$ (1,955)	\$ 274	
State income tax (benefit) expense	43		-		43	
Permanent difference	35		(84)	(49)	
Other	6				6	
Net change in deferred tax asset valuation allowance	-		600		600	
Total income tax provision (benefit)	\$ 2,313		\$ (1,439)	\$ 874	

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Year Ended December 31, 2011	Continuing		Discontinued		Total	
	Operations	%	Operations	%	34	%
Statutory rate	34	%	34	%	34	%
Tax (benefit) expense at statutory rate	\$ 1,787		\$ (141)	\$1,646	
State income tax (benefit) expense	215		-		215	
Permanent difference	28		14		42	
Net change in deferred tax asset valuation allowance	(1,741)	-		(1,741)	
Total income tax provision (benefit)	\$ 289		\$ (127)	\$162	

Management has evaluated the positions taken in connection with the tax provisions and tax compliance for the years included in these financial statements. The Company believes that all of the positions it has taken will prevail on a more likely than not basis. As such no disclosure of such positions was deemed necessary. Management continuously estimates its ability to recognize a deferred tax asset related to prior period net operating loss carry forwards based on its anticipation of the likely timing and adequacy of future net income.

As of December 31, 2013 and 2012, management determined using the “more likely than not” criteria for recognition that upon sale of the Pipeline asset, the Company would not be able to utilize the state net operating loss carryforwards associated with TPC and the Tennessee oil and gas properties, and therefore established an allowance for these state net operating loss carryforwards. The total valuation allowance at December 31, 2013 and 2012 was \$790,000 and \$600,000, respectively.

As of December 31, 2011, management determined using the “more likely than not” criteria for recognition that increases in current projections of taxable income were sufficient so the valuation allowance was no longer necessary. Therefore, the \$1.7 million valuation allowance was removed.

As of December 31, 2013, the Company had net operating loss carry forwards of approximately \$19.7 million which will expire between 2019 and 2031 if not utilized. Our open tax years include all returns filed for 2010 and later. In addition, any of the Company’s NOLs for tax reporting purposes are still subject to review and adjustment by both the Company and the IRS to the extent such NOLs should be carried forward into an open tax year.

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The Company's deferred tax assets and liabilities are as follows: (in thousands)

	Year Ended December 31,	
	2013	2012
Net deferred tax assets - current:		
Charitable contribution	\$62	\$-
Bad debt	\$68	\$-
Total deferred tax assets – current	\$130	\$-
Net deferred tax assets (liabilities) – noncurrent:		
Net operating loss carryforwards	\$7,723	\$8,550
Oil and gas properties	979	(154)
Property, Plant and Equipment	(1,562)	963
Asset retirement obligation	565	517
Tax credits	196	158
Miscellaneous	98	-
Valuation allowance	(790)	(600)
Total deferred tax assets – noncurrent	\$7,209	\$9,434
Net deferred tax asset	\$7,339	\$9,434

14. Quarterly Data and Share Information (unaudited)

The following tables sets forth for the fiscal periods indicated, selected consolidated financial data (In thousands, except per share data)

Fiscal Year Ended 2013	2nd			
	1st Qtr	Qtr	3rd Qtr	4th Qtr
Revenues	\$4,314	\$3,871	\$4,034	\$3,481
Net income from continuing operations	978	805	535	638
Net (loss) from discontinued operations	(41)	(33)	(54)	(9)
Income per common share from continuing operations	\$0.02	\$0.01	\$0.01	\$0.01
(Loss) per common share from discontinued operations	\$(0.00)	\$(0.00)	\$(0.00)	\$(0.00)

Fiscal Year Ended 2012	2nd			
	1st Qtr	Qtr	3rd Qtr	4th Qtr
Revenues	\$4,962	\$5,222	\$5,806	\$4,567
Net income from continuing operations	954	1,152	1,279	859
Net (loss) from discontinued operations	(81)	(65)	(60)	(4,105)
Income per common share from continuing operations	\$0.02	\$0.02	\$0.02	\$0.01
(Loss) per common share from discontinued operations	\$(0.00)	\$(0.00)	\$(0.00)	\$(0.07)

15. Supplemental Oil and Gas Information (unaudited)

Information with respect to the Company's oil and gas producing activities is presented in the following tables. Estimates of reserves quantities, as well as future production and discounted cash flows before income taxes, were determined by LaRoche Petroleum Consultants Ltd. All of the Company's reserves were located in the United States.

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Capitalized Costs Related to Oil and Gas Producing Activities

The table below reflects our capitalized costs related to our oil and gas producing activities at December 31, 2012 and 2011 (in thousands):

	Years Ended	
	December 31,	
	2013	2012
Proved oil and gas properties	\$45,101	\$43,351
Unproved properties	736	457
Total proved and unproved oil and gas properties	\$45,837	\$43,808
Less accumulated depreciation, depletion and amortization	(21,714)	(19,108)
Net oil and gas properties	\$24,123	\$24,700

Oil and Gas Related Costs

The following table sets forth information concerning costs incurred related to the Company's oil and gas property acquisition, exploration and development activities (in thousands):

	Years Ended December		
	31,		
	2013	2012	2011
Property acquisitions proved	\$-	\$-	\$-
Property acquisitions unproved	488	188	-
Exploration cost	914	4,608	708
Development cost	998	2,649	8,278
Total	\$2,400	\$7,445	\$8,986

Results of Operations from Oil and Gas Producing Activities

The following table sets forth the Company's results of operations from oil and gas producing activities (in thousands):

	Years Ended December 31,		
	2013	2012	2011
Revenues	\$15,325	\$19,885	\$16,862
Production costs and taxes	(4,854)	(5,610)	(5,310)
Depreciation, depletion and amortization	(2,606)	(3,044)	(2,195)
Income from oil and gas producing activities	\$7,865	\$11,231	\$9,357

In the presentation above, no deduction has been made for indirect costs such as general corporate overhead or interest expense. No income taxes are reflected above due to the Company's operating tax loss carry-forward position.

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Estimated Quantities of Oil and Gas Reserves

The following table sets forth the Company's net proved oil and gas reserves and the changes in net proved oil and gas reserves for the years ended December 31, 2011, 2012 and 2013. All of the Company's proved reserves are located in the United States of America.

	Oil (MBbl)	Gas (MMcf)	MBOE
Proved reserves at December 31, 2010	2,496	27	2,500
Revisions of previous estimates	10	3	11
Improved recovery			
Purchase of reserves in place			
Extensions and discoveries	274	-	274
Production	(189)	(26)	(193)
Sales of reserves in place			
Proved reserves at December 31, 2011	2,591	4	2,592
Revisions of previous estimates	(337)	61	(327)
Improved recovery	-	-	-
Purchase of reserves in place	-	-	-
Extensions and discoveries	186	-	186
Production	(227)	(43)	(234)
Sales of reserves in place	-	-	-
Proved reserves at December 31, 2012	2,213	22	2,217
Revisions of previous estimates	(153)	16	(151)
Improved recovery	-	-	-
Purchase of reserves in place	-	-	-
Extensions and discoveries	170	-	170
Production	(166)	(38)	(172)
Sales of reserves in place	(24)	-	(24)
Proved reserves at December 31, 2013	2,040	-	2,040
Proved developed reserves at:			
December 31, 2010	1,800	27	1,804
December 31, 2011	1,939	4	1,940
December 31, 2012	1,822	22	1,826
December 31, 2013	1,575	-	1,575
Proved undeveloped reserves at:			
December 31, 2010	696	-	696
December 31, 2011	652	-	652
December 31, 2012	391	-	391

December 31, 2013

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The Company's Proved Undeveloped Reserves at December 31, 2013 included 29 locations as compared to 23 locations at December 31, 2012. The future development cost related to the Company's Proved Undeveloped locations at December 31, 2013 was approximately \$9.6 million. The Company intends to fund the drilling of these locations through operating cash flow and, as needed, supplement the funding by drawing on the Company's credit facility.

The following table identifies the reserve value by category and the respective present values, before income taxes, discounted at 10% as a percentage of total proved reserves (in thousands):

	Year Ended 12/31/13			Year Ended 12/31/12			Year Ended 12/31/11			
	Oil	Gas	Total	Oil	Gas	Total	Oil	Gas	Total	
Total proved reserves year-end reserve report	\$47,856	-	\$47,856	\$53,906	\$ 5	\$53,911	\$69,748	\$ 15	\$69,763	
Proved developed producing reserves (PDP)	\$34,440	-	\$34,440	\$42,621	\$ 5	\$42,626	\$46,606	\$ 15	\$46,621	
% of PDP reserves to total proved reserves	72	% -	72	% 79	% -	79	% 67	% -	67	%
Proved developed non-producing reserves	\$4,868	-	\$4,868	\$3,234	-	\$3,234	\$3,977	-	\$3,977	
% of PDNP reserves to total proved reserves	10	% -	10	% 6	% -	6	% 6	% -	6	%
Proved undeveloped reserves (PUD)	\$8,548	-	\$8,548	\$8,051	-	\$8,051	\$19,165	-	\$19,165	
% of PUD reserves to total proved reserves	18	% -	18	% 15	% -	15	% 27	% -	27	%

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows from the Company's proved oil and gas reserves is presented in the following table (in thousands):

	Years Ended December 31,		
	2013	2012	2011
Future cash inflows	\$183,801	\$194,941	\$229,366
Future production costs and taxes	(82,307)	(82,069)	(82,086)
Future development costs	(11,162)	(7,894)	(12,611)
Future income tax expenses	(18,910)	(19,472)	(34,750)
Future net cash flows	71,422	85,506	99,919
Discount at 10% for timing of cash flows	(32,714)	(40,152)	(48,010)
Standardized measure of discounted future net cash flows	\$38,708	\$45,354	\$51,909

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The following are the principal sources of change in the standardized measure of discounted future net cash flows from the Company's proved oil and gas reserves (in thousands):

	Years Ended December 31,		
	2013	2012	2011
Balance, beginning of year	\$45,354	\$51,909	\$48,344
Sales, net of production costs and taxes	(10,471)	(14,275)	(11,552)
Discoveries and extensions, net of costs	4,047	6,967	10,923
Purchase of reserves in place	-	-	-
Sale of reserves in place	(767)	-	-
Net changes in prices and production costs	(1,277)	(6,067)	15,428
Revisions of quantity estimates	(4,306)	(9,883)	343
Previously estimated development cost incurred during the year	3,149	8,760	5,346
Changes in future development costs	(1,392)	(1,919)	(1,109)
Changes in production rates (timing) and other	368	(5,657)	(2,336)
Accretion of discount	4,593	6,223	4,376
Net change in income taxes	(590)	9,296	(17,854)
Balance, end of year	\$38,708	\$45,354	\$51,909

Estimated future net cash flows represent an estimate of future net revenues from the production of proved reserves using average sales prices, along with estimates of the operating costs, production taxes and future development and abandonment cost (less salvage value) necessary to produce such reserves. Future income taxes were calculated by applying the statutory federal and state income tax rates to pre-tax future net cash flows, net of the tax basis of the properties and utilizing available tax loss carryforwards related to oil and gas operations. The prices used for December 31, 2013, 2012, and 2011, were \$90.11, \$88.08, \$88.53 per barrel of oil and \$0.00, \$2.76, \$4.16, per MCF of gas, respectively. The Company's proved reserves as of December 31, 2013, 2012 and 2011 were measured by using commodity prices based on the twelve month unweighted arithmetic average of the first day of the month price for the period January through December. No deduction has been made for depreciation, depletion or any indirect costs such as general corporate overhead or interest expense.