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)

xAnnual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended December 31, 2013 or

o Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the transition period from __________ to __________.
Commission File 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 o x 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 o x 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 x o 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) x Yes o No

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. o

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

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was 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	Average Sales Price	
	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	(Per BOE)	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

YearsEnded December 31,	Gross Production		Net Production		Cost of Net Production	Average Sales Price	
	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	(Per BOE)	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 31,					
	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