TENGASCO INC
Form 10-K
March 29, 2012

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

REPORT ON FORM 10-K

(Mark one)

[X} Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended December 31, 2011 or

[ ] Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the transition period from __________ to __________.

Commission File No. 1-15555

TENGASCO, INC.

(name of registrant as specified in its charter)

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

11121 Kingston Pike, Suite E, Knoxville, TN	37934
(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 [ ] [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 [ ] [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] [ ] 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 [ ] 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.[ ]

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

Large Accelerated Filer [ ] Accelerated Filer [ ]

Non-accelerated Filer [ ] Smaller Reporting Company [X]

(Do not check if a Smaller Reporting Company)

Indicate by checkmark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes [ ] No [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 $28 million (June 30, 2011 closing price $0.74).

The number of shares outstanding of the registrant's $.001 par value common stock as of the close of business on March 16, 2012 was 60,737,413.

Documents Incorporated By Reference

The information required by Part III of this Report on Form 10-K, to the extent not set forth herein, is incorporated herein by reference from the registrant's definitive proxy statement for the Annual Meeting of Shareholders to be held on May 29, 2012 to be filed with the Securities and Exchange Commission pursuant to Regulation 14A not later than 120 days after the close of the registrant's fiscal year.

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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 t future. Forward-looking statements also include statements regarding revenue margins, expenses, and earnings analysis for 2011 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.

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.

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.

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 gas production is the Swan Creek field in Tennessee.

The Company's wholly-owned subsidiary, Tengasco Pipeline Corporation ("TPC") owns and operates 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's wholly-owned subsidiary, Manufactured Methane Corporation ("MMC") operates treatment and delivery facilities using the latest developments in available treatment technologies for the extraction of methane gas from nonconventional sources for delivery through the nation's existing natural gas pipeline system, including the Company's pipeline system in Tennessee for eventual sale to natural gas customers.

The Company also has 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, "General 4. Management Agreement with Hoactzin"). Peter E. Salas, the Chairman of the Board of Directors of the Company, is the controlling person of Hoactzin. He is also the sole shareholder and controlling person of Dolphin Management, Inc., the general partner of Dolphin Offshore Partners, L.P., which is the Company's largest shareholder.

General

1. The Kansas Properties

The Kansas Properties presently include 185 producing oil wells in central Kansas. Our management and staff have a great deal of Kansas exploration and production experience. We have onsite production management and field personnel working in Kansas.

In 2011, the Company continued to focus on both development drilling and to a lesser degree, exploration drilling. Many of the wells that were drilled, were on leases that are still in effect because they are being held by existing production. The leases provide for a landowner royalty of 12.5%. Some wells are subject to an overriding royalty interest from 0.5% to 9%. Other than such wells bearing overriding royalties, the Company maintains a 100% working interest in most of its older wells and any undrilled acreage in Kansas. The terms for most of the Company's newer leases in Kansas are from three to five years.

During 2011, the Company drilled 25 gross wells. The Company has a 100% working interest in all of the wells. The success rate was 16 producers and 9 dry holes for the 25 wells drilled by the Company in Kansas.

Kansas as a whole is of major significance to the Company. The majority of the Company's current reserve value, current production, revenue, and future development objectives are centered in the Company's ongoing interest in Kansas. By using 3-D seismic evaluation on existing locations owned by the Company in Kansas, the Company has added and continues to add proven direct offset locations.

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 per 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 will 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").

Nine of the ten wells in the program were completed as oil producers and during the 4th quarter 2011 had gross production of approximately 38 barrels per day in total. Hoactzin paid a total of $3.85 million (the "Purchase Price") for its interest in the Program resulting in the Payout Point being determined as $5.2 million. The Purchase Price paid by Hoactzin for its interest in the Program wells exceeded the Company's actual drilling cost of approximately $2.6 million for the ten wells by more than $1 million.

In 2011, the wells from the Program produced 15.5 MBbls of which 10.2 MBbls were net to Hoactzin. As of December 31, 2011, net revenues received by Hoactzin from the Program totaled $3.9 million which leaves a balance of $1.3 million until the Payout Point is reached.

Although production level of the Program wells will decline over time in accordance with expected decline curves, based on the drilling results of the Program wells to date and the current price of oil, the Program wells are now expected to reach the Payout Point by December 31, 2013. However, under the terms of the agreement reaching the Payout Point could be accelerated by applying 75% of the net profits Hoactzin receives from the methane extraction project developed by MMC at the Carter Valley, Tennessee landfill (the "Methane Project"), toward reaching the Payout Point. (The Methane Project is discussed in greater detail below.)

As part of a series of transactions with Hoactzin relating to the Program and the Methane Project, on September 17, 2007 the Company entered into another agreement with Hoactzin providing that if the Program and the Methane Project in combination failed to return net revenues to Hoactzin equal to 25% of the Purchase Price by December 31, 2009, then Hoactzin had an option to exchange up to 20% of its net profits interest in the Methane Project for convertible preferred stock to be issued by the Company.

However, as stated, net revenues received by Hoactzin from the wells in the Program through December 31, 2011 totaled $3.9 million thereby reaching the Purchase Price and therefore no preferred stock will ever be issued to Hoactzin.

The reserve information for the parties' respective Ten Well Program interests as of December 31, 2011 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 2011 as required by SEC regulations. The table below reflects eventual pay as occurring through the realization of proceeds at prices used in the reserve report dated December 31, 2011 of approximately $88.53 per barrel.

Reserve Information for Ten Well Program Interest for the Year Ended December 31, 2011

	Barrels Attributable to Party's Interest MBbl	Future Cash Flows Attributable to Party's Interest (in thousands)	Present Value of Future Cash Flows Attributable to Party's Interest (in thousands)
Tengasco	102.9	$5,744	$2,241
Hoactzin Partners, L.P.	37.7	$2,285	$1,519

As of December 31, 2011, the original invested amount of $3.85 million has been reduced to zero. Consequently, Hoactzin is precluded by these results from any possibility of exercising its contingent option under the exchange agreement to convert into preferred stock. All of the $3.85 million paid has been from the Ten Well Program.

B. Kansas Production

The Company's gross oil production in Kansas increased in 2011 from 2010 levels. In 2011, the Company produced 241 MBbls in Kansas compared to 224 MBbls in 2010. The 15 wells that were polymered in 2011 produced 32 MBbl and the 16 successful new wells drilled in 2011 produced approximately 16 MBbl.

The capital projects undertaken by the Company in 2011 were funded from cash flow and approximately $2 million from bank borrowings. The Company plans to have a more active drilling program in 2012. However, if future oil prices should decrease, it may cause the Company to reduce its anticipated 2012 capital spending. The Company has a derivative agreement providing a $65 floor on 10,000 barrels of oil per month from January 2012 through December 2012 to minimize the effect of an oil price decrease.

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. Amoco successfully drilled two natural gas discovery wells in the Swan Creek Field to the Knox Formation. In the mid-1980's, however, development of this field was cost prohibitive due to a substantial decline in worldwide oil and gas prices which was further exacerbated by the high cost of constructing a necessary 23-mile pipeline to deliver gas from the Swan Creek Field to the closest market. In July 1995, the Company acquired the Swan Creek leases and began development of the field.

A. Swan Creek Pipeline Facilities

The Company's completed pipeline system is owned and operated by TPC and extends 65 miles from the Swan Creek Field to several meter stations in Kingsport, Tennessee. The pipeline system was built for a total cost of $16.4 million. The Company reviews the carrying value of the pipeline for impairment whenever events and circumstances indicate that the carrying value of an asset may not be recoverable from the estimated future cash flows expected to result from its use and eventual disposition. In cases where undiscounted expected future cash flows are less than the carrying value, an impairment loss is recognized equal to an amount by which the carrying value exceeds the fair value of assets.

The factors considered by management in performing this assessment include current operating results, trends, and prospects, as well as the effects of obsolescence, demand, competition, and other economic factors. During 2010 there were indicators the pipeline may be impaired and the Company performed an assessment of the carrying value as of December 31, 2010 based on expected future cash flows. The assessment resulted in the Company recording an impairment of approximately $5.0 million for the year ended December 31, 2010. At December 31, 2011 management determined there were no indicators of impairment, therefore, there is no impairment charge for the year ended December 31, 2011. The net book value of the pipeline system was approximately $6.9 million and $7.0 million at December 31, 2011 and 2010, respectively.

B. Swan Creek Production and Development

The Company has concluded based on the results of previously drilled wells and seismic data that drilling new gas wells in the Swan Creek Field would not achieve any significant increase in daily gas production totals from the Field. Current wells in production in the Swan Creek Field would be capable of and would likely produce all the remaining reserves in that Field. As a result, the Company has not drilled any new gas wells in the Swan Creek Field since 2004.

Because no drilling for natural gas in the Knox formation in Swan Creek is anticipated in the future, the current production levels less decline are the sole value of natural gas reserves and natural gas production. The existing production from the current 12 wells producing natural gas are showing typical Appalachian production declines, which exhibit a long-lived nature but more modest volumes. The experienced decline in actual production levels from existing wells in the Swan Creek Field was expected and predictable. Although there can be no assurance, the Company expects these natural rates of decline in the future will be comparable to historical decline experienced over the 2010-2011 period.

During 2011, the Company had 12 producing gas wells and 4 producing oil wells in the Swan Creek Field. Gross gas sales from the Swan Creek Field during 2011 averaged 90 Mcfd compared to 93 Mcfd in 2010. Gross oil sales volumes from the Swan Creek field during 2011 averaged 15 BOPD compared to 17 BOPD in 2010.

The Company continues to evaluate nearby properties for the purpose of exploring the rim of the Swan Creek anticline for Devonian Shale gas production. The Company may seek development of these properties with other industry partners as it remains possible that when more than one well is drilled, it may be economically feasible to treat (if necessary) the produced gas as required, and to construct gathering facilities necessary to connect to the Company's pipeline to bring the gas to market. To date no industry partners have been found by the Company to further explore these properties and no assurances can be made that such a partner can be found or that an agreement may be reached with such partner on terms acceptable to the Company. During 2011, the Company drilled one exploratory well in an attempt to find Devonian Shale gas. Although the well did not produce oil or natural gas in commercial quantities, this well was a first step in defining the structure. In addition, the company plans to drill additional oil prospects in Swan Creek.

3. Methane Project

On October 24, 2006, the Company signed a twenty-year Landfill Gas Sale and Purchase Agreement (the “Agreement”) with BFI Waste Systems of Tennessee, LLC (“BFI”), an affiliate of Allied Waste Industries (“Allied”). In 2008, Allied merged into 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 installed a proprietary combination of advanced gas treatment technology to extract the methane component of the purchased gas stream. Methane is the principal component of natural gas and makes up about half of the purchased raw gas stream by volume. The Company constructed a pipeline to deliver the extracted methane gas to the Company’s existing pipeline (the “Methane Project”).

The total cost for the Methane Project, including pipeline construction, was approximately $4.5 million. The costs of the Methane Project were funded primarily by (a) the money received by the Company from Hoactzin to purchase its interest in the Ten Well Program which exceeded the Company’s actual costs of drilling the wells in that Program by more than $1 million; (b) cash flow from the Company’s operations; and (c) $0.8 million of the funds the Company borrowed under its then credit facility with Sovereign Bank of Dallas, Texas (“Sovereign Bank”). Methane gas produced by the project facilities was initially mixed in the Company’s pipeline and delivered and sold to Eastman under the terms of the Company’s natural gas purchase and sale agreement with Eastman. The gas supply from this landfill is projected to grow over the years as the underlying operating landfill continues to expand and generate additional naturally produced gas, and for several years following the closing of the landfill, estimated by Republic to occur in 2041. Gas production will continue in commercial quantities up to 10 years after closure of the landfill.

MMC declared startup of commercial operations on April 1, 2009. During the month of April, the facility produced and sold 14 MMcf of methane gas to Eastman and was online about 91% of the calendar month. System maintenance and landfill supply adjustments accounted for the remainder of the time. On May 1, 2009, Eastman advised MMC that it was suspending deliveries of the methane gas stream pending approval by the federal Environmental Protection Agency (“EPA”) of Eastman’s petition for inclusion of treated methane gas as natural gas within the meaning of the EPA’s continuous emission monitoring rules applicable to Eastman’s large boilers during the annual “smog season” beginning May 1st of each year. Although Eastman had begun seeking this approval in February, 2009, with the assistance of the Air Quality Department of the Tennessee Department of Environment and Conservation, the EPA had not acted by May 1, 2009. Eastman furnished to the EPA information provided by MMC that establishes that the methane gas stream is better fuel under the rule standards than even “natural” gas, which is technically defined in the smog season rules to include gas being “found in geologic formations beneath the earth’s surface”. Because approval was not promptly received, MMC was forced to seek alternative markets for the methane gas stream.

The Company concluded an agreement for sale of the methane gas to Hawkins County Gas Utility District, a local utility commencing August 1, 2009 on a month to month basis. Effective September 1, 2009 the Company also began sales of its Swan Creek gas production to Hawkins County

Gas Utility District, because the physical mixing of Swan Creek natural gas with MMC's methane gas caused Eastman to suspend deliveries of both categories of gas as mixed.

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.

MMC's plant is capable of remaining in operation for a full 24 hours per day. Daily production decreases during days when the plant operates less than 24 hours, whether due to any equipment or collection system supply issue. The primary reason experienced for less-than- 24-hour operation since April 2009 has been frequent spiking in the oxygen content in the raw gas collected by Republic and delivered to the plant, rather than being caused by equipment malfunctions in MMC's plant. Oxygen spikes shut down MMC's equipment for safety reasons, as high oxygen gas streams become explosive under the compression required in our treatment process. In mid-2010 the oxygen spikes increased from occasional spikes to an almost constant level of oxygen that caused longer downtime to our equipment. MMC's plant had minimal production of sales methane during the fourth quarter of 2010 of approximately 5,500 MMBTU of methane gas for an average of 60 MMBTU per day. The MMC plant had no production of sales methane during the third quarter 2010. During the second quarter in 2010, the facility produced approximately 27,000 MMBtu of methane, an average of 300 MMBtu per day. In the first quarter of 2010, the facility had produced about 19,600 MMBtu, an average of 220 MMBtu per day.

These problems continued throughout 2011, with average production being 81MMBtu per day for the twelve month period ending December 31, 2011 or a total yearly production of 29,469 MMBtu. The final two months of 2011 had no production at the methane plant, due to additions being made to MMC's facility to allow installation and fueling of the electric generator described below.

In order to address the issue of significant plant downtime due to oxygen levels, MMC sought to eliminate the recycling of a process methane gas stream within the methane plant. That recycling had the effect of increasing the oxygen percentages at plant inlet when it was recycled to the plant inlet in order to extract some still-remaining methane. By ceasing use of that recycle stream, methane extraction efficiency would be reduced, but run time would be increased by avoiding some oxygen-caused shutdowns for safety. MMC determined the recycle gas stream could be repurposed to be used to fuel an electric generator onsite, which would offset electric utility costs at the methane plant, as well as providing an additional revenue source. 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 methane plant site for generation of electricity. Total cost of the generator including installation and interconnection with the power grid is approximately $1.1 million.

On January 25, 2012, MMC commenced sales of electricity generated at the Carter Valley site of its methane extraction facilities. 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 only 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 $.129 per KWH. Current electric production is about 22,800 KWH per day for gross revenue of about $2,950 per day. The contract terminates in January 2022 but can be extended for an additional ten years at a purchase price to be negotiated at that time. Methane gas sales will continue under the Atmos contract simultaneously with electricity sales and the same one-eighth royalty on electricity revenues will be paid to the landfill owner as is paid on methane revenues. The electric generation also reduces oxygen input to the methane plant, which along with improvements to the collection system in the field have together resulted in consistently high levels of in-service time since January 25, 2012 and through the date of this Report. Although a portion of the gas used for generation of electricity will not be available for methane extraction, the use of the gas for electricity generation is equivalent to sale of the methane for almost $15per MMBtu, more than double the price currently received for methane sales and six times the current natural gas spot market price.

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. Any net profits from the Methane Project, if received by Hoactzin, would be applied towards the determination of the Payout Point (as defined above) for the Ten Well Program. When the Payout Point is reached from either the revenues from the wells drilled in the Program or the Methane Project or a combination thereof, Hoactzin's net profits interest in the Methane Project will decrease to 7.5%. The agreed method of calculation of net profits takes into account specific costs and expenses as well as gross revenues for the project. As a result of the startup costs and ongoing operating expenses, and reduced production levels discussed above, no net profits as defined have been generated from project startup in April, 2009 through December 31, 2011 for payment to Hoactzin under the net profits interest conveyed. 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 September 17, 2007, the Company entered into a drilling program with Hoactzin Partners, L.P. ("Hoactzin") for ten wells consisting of approximately three wildcat wells and seven developmental wells to be drilled on the Company's Kansas Properties (the "Ten Well Program"). Peter E. Salas, the Chairman of the Board of Directors of the Company, is the controlling person of Hoactzin. He is also the sole shareholder and controlling person of Dolphin Management, Inc. and the general partner of Dolphin Offshore Partners, L.P., which is the Company's largest shareholder.

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

In March 2008, the Company drilled and completed the tenth and final well in the Ten Well Program. Of the ten wells drilled, nine were completed as oil producers and are currently producing approximately 38 barrels per day in total. Hoactzin paid a total of $3.85 million (the "Purchase Price") for its interest in the Ten Well Program resulting in the Payout Point being determined as $5.2 million. The amount paid by Hoactzin for its interest in the Program wells exceeded the Company's actual drilling costs of approximately $2.8 million for the ten wells by more than $1 million.

Although production level of the Program wells will decline with time in accordance with expected decline curves for these types of wells, based on the drilling results of the wells in the Ten Well Program and the current price of oil, the Program wells would be expected to reach the Payout Point by December 31, 2013 solely from the oil revenues from the wells. However, under the terms of the Company's agreement with Hoactzin, reaching the Payout Point may be accelerated by operation of a second agreement by which Hoactzin will apply 75% of the net profits it may receive from a methane extraction project discussed below developed by the Company's wholly-owned subsidiary, Manufactured Methane Corporation ("MMC"), to the Payout Point. Those methane project net profits if applied may result in the Payout Point being achieved sooner than relying solely upon revenues from the Program wells. However, as discussed below, although the Methane Project has been placed into operation, no Methane Project net profits have been generated or paid to Hoactzin through December 31, 2011.

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

Through December 31, 2011, no payments have been made to Hoactzin for its 75% net profits interest in the Methane Project, because no net profits have been generated. The method of calculation of the net profits interest takes into account specific costs and expenses as well as gross revenues for the project. As a result of the startup costs and ongoing operating expenses, no net profits as defined in the agreement have been generated from project startup in April, 2009 through December 31, 2011 for payment to Hoactzin under the net profits interest conveyed. When the Payout Point is reached from either the revenues from the wells drilled in the Ten Well Program or Hoactzin's share of the net profits from the Methane Project or a combination thereof, Hoactzin's net profits interest in the Methane Project will decrease to a 7.5% net profits interest.

On September 17, 2007, the Company also entered into a third simultaneous agreement with Hoactzin providing that if the Program and the Methane Project interest in combination failed to return net revenues to Hoactzin equal to 25% of the Purchase Price it paid for its interest in the Ten Well Program by December 31, 2009, then Hoactzin would have an option to exchange up to 20% of its net profits interest in the Methane Project for convertible preferred stock to be issued by the Company with

a liquidation value equal to 20% of the Purchase Price less the net proceeds received at the time of any exchange. By December 31, 2011, the amount of net revenues received by Hoactzin from the Ten Well Program has reduced the Company's obligation to Hoactzin for the amount of the funds it had advanced for the Purchase Price from $3.85 million to zero, thereby reaching the purchase price and therefore no preferred stock will ever be issued to Hoactzin.

On December 18, 2007, the Company entered into a Management Agreement with Hoactzin. On that same date, the Company also entered into an agreement with Charles Patrick McInturff employing him as a Vice-President of the Company. Pursuant to the Management Agreement with Hoactzin, Mr. McInturff's duties while he is employed as Vice President of the Company will include the management on behalf of Hoactzin 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 consideration for the Company entering into the Management Agreement, Hoactzin agreed that it will be responsible to reimburse the Company for the payment of one-half of Mr. McInturff's salary, as well as certain other benefits he receives during his employment by the Company. In further consideration for the Company's agreement to enter into the Management Agreement, Hoactzin granted to the Company an option to participate in up to a 15% working interest on a dollar for dollar cost basis in any new drilling or workover activities undertaken on Hoactzin's managed properties during the term of the Management Agreement. The term of the Management Agreement ends on the earlier of the date Hoactzin sells its interest in its managed properties or five years (December 2012).

The Company became the operator of certain properties owned by Hoactzin in connection with the Management Agreement. 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 operated properties located in federal offshore waters in favor of the Bureau of Ocean Energy Management, Regulation and Enforcement, and certain private parties.

In connection with the issuance of these bonds the Company entered into a Payment and Indemnity Agreement with IndemCo that guarantees payment of any bonding liabilities incurred by IndemCo. Dolphin Direct Equity Partners, LP co-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 the obligations. Dolphin Direct Equity Partners is a private equity fund controlled by Peter E. Salas that has a significant economic interest in Hoactzin.

As operator, the Company has routinely contracted in its name for goods and services with vendors in connection with its operation of the Hoactzin properties. In practice, Hoactzin pays directly these invoices for goods and services that are contracted in the Company's name. During late 2009 and early 2010, Hoactzin undertook several significant operations, for which the Company contracted in the ordinary course. As a result of the operations performed in late 2009 and early 2010, Hoactzin experienced significant past due balances to several vendors, a portion of which are included on the Company's balance sheet as of December 31, 2011. Payables related to these and ongoing operations remained outstanding at the end of 2011 and 2010 in the amount of $0.3 million and $1.0 million respectively. Because this amount is material, the Company recorded the Hoactzin-related payables and

the corresponding receivable from Hoactzin as of December 31, 2011 in its Consolidated Balance Sheets under "Accounts payable – other" and "Accounts receivable – related party. The Company expects that Hoactzin will fully satisfy all these vendor obligations with its own resources.

No Tengasco funds have been advanced by Tengasco to pay any obligations of Hoactzin. No borrowing capability of Tengasco has been or is expected to be used by the Company in connection with its obligations under the Management Agreement. The Management Agreement terminates at the earlier of the date of sale, if any, by Hoactzin of its managed properties, or December 2012.

5. Other Areas of Development

The Company is continuing to review and analyze potential acquisitions of additional existing oil and gas production in areas of Kansas, Oklahoma, and Texas. Whether the Company will proceed with any such acquisition it deems appropriate will be dependent on a number of factors, including available financing, oil and gas prices, acquisition prices, etc. Future economic conditions, including any sharp decline in oil prices, will have an adverse impact on the Company's ability to acquire additional properties as it will reduce the Company's cash flows and borrowing base under its credit facility with F&M Bank and Trust Company. Accordingly, there is no assurance that a suitable property will become available or even if such property becomes available that terms will be established leading to a completion of such a purchase.

The Company has evaluated other geological structures in the East Tennessee area that are similar to the Swan Creek Field. While these areas are of interest, and may be further evaluated at some future time, based on its review to date the Company does not currently intend to actively explore these areas with its own funds. The Company may consider entering into partnerships where further exploration and drilling costs can be largely borne by third parties. There can be no assurances that any third party would participate in a drilling program in these structures, that any of these prospects will be drilled, and if they were drilled that they would result in commercial production.

The Company also intends to establish and explore all business opportunities for connection of the pipeline system owned by the Company's subsidiary TPC to other sources of natural gas or gas produced from non-conventional sources so that revenues from third parties for transportation of gas across the pipeline system may be generated. Although no assurances can be made, such connections may also enable the Company to purchase natural gas from other sources and to then market natural gas to new customers in the Kingsport, Tennessee area at retail rates under a franchise agreement already granted to the Company by the City of Kingsport, subject to approval by the Tennessee Regulatory Authority.

The Company also intends to continue to explore other opportunities such as its Methane Project in Church Hill, Tennessee to obtain natural gas or substitutes for natural gas from non-conventional sources if such gas can be economically treated and tendered in commercial volumes for transportation not only through the Company's existing pipeline system but by other delivery mechanisms and through other interstate or intrastate pipelines or local distribution companies for the purposes of supplementing the Company's revenues from the sale of the methane gas produced by these projects.

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. The principal markets for the Company’s natural gas and methane production are local utilities, private industry end-users, and gas marketing companies.

Gas production from the Swan Creek Field can presently be delivered through the Company’s completed pipeline to the Powell Valley Utility District in Hancock County, Hawkins County Gas Utility, Eastman and BAE in Sullivan County, other industrial customers in the Kingsport area, as well as gas marketing companies. The Company has acquired all necessary regulatory approvals and necessary property rights for the pipeline system. The Company’s pipeline can provide transportation service not only for gas produced from the Company’s wells, but also for small independent producers in the local area as well or other pipelines that may be connected to the Company’s pipeline in the future.

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. Crude oil produced by the Company in Tennessee is sold to the Ashland Refinery in Kentucky and is transported to the refinery by contracted truck delivery at the Company’s expense.

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 companies as available in the Swan Creek Field area and various drilling contractors in Kansas.

Distribution Methods of Products or Services

Crude oil is normally delivered to refineries in Tennessee and Kansas by tank truck and natural gas is distributed and transported by pipeline.

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

The Company’s contemplated oil and gas exploration activities in the States of Tennessee and 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.

The Company has numerous competitors in the State of Tennessee that are in the business of exploring for and producing oil and natural gas in Kentucky and East Tennessee areas. 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.

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.

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. They are usually issued within one week of application. 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.

The Company is presently dependent upon a small number of customers for the sale of gas from the Swan Creek Field and 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. In addition the transportation service offered by TPC is subject to regulation by the Tennessee Regulatory Authority to the extent of certain construction, safety, tariff rates and charges, and nondiscrimination requirements under state law. These requirements are typical of those imposed on regulated common carriers or utilities in the State of Tennessee or in other states. TPC presently has all required tariffs and approvals necessary to transport natural gas to all customers of the Company.

The City of Kingsport, Tennessee has enacted an ordinance granting to TPC a franchise for twenty years (expires June 20, 2020) to construct, maintain and operate a gas system to import, transport, and sell natural gas to the City of Kingsport and its inhabitants, institutions and businesses for domestic, commercial, industrial and institutional uses. This ordinance and the franchise agreement it authorizes also require approval of the Tennessee Regulatory Authority under state law. The Company will not initiate the required approval process for the ordinance and franchise agreement until such time that it can supply gas to the City of Kingsport. Although the Company anticipates that regulatory approval would be granted, there can be no assurances that it would be granted, or that such approval would be granted in a timely manner, or that such approval would not be limited in some manner by the Tennessee Regulatory Authority.

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.

The State of Tennessee also requires the posting of a bond to ensure that the Company's wells are properly plugged when abandoned. A separate $2,000 bond is required for each well drilled. The Company currently has the requisite amount of bonds in effect.

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.

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’s Board of Directors has adopted resolutions to form 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 that 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 29 full time employees and no part-time employees.

Executive Officers of the Registrant

Identification of Executive Officers

The following table sets forth the names of all current executive officers of the Company. These persons will serve until their successors are elected or appointed and qualified, or their prior resignations or terminations.

Name	Positions Held	Date of Initial Election of Designation
Jeffrey R. Bailey	Chief Executive Officer[1]	6/17/2002
Charles Patrick McInturff	Vice-President	12/18/2007
Cary V. Sorensen	Vice-President; General Counsel; Secretary	7/09/1999
Michael J. Rugen	Chief Financial Officer	9/28/2009

Business Experience[2]

Charles Patrick McInturff is 59 years old. Mr. McInturff received a Bachelor of Science Degree in Civil Engineering from Texas A&M University in 1975. He is a Registered Professional Engineer from Texas and a member of the Society of Petroleum Engineers. Before joining the Company he was Vice President of Operations of Capco Offshore, Inc. and related companies in Houston from October 2006 until December 2007 responsible for managing and supervising offshore operations and workovers and identification and evaluation of drilling and workover candidates.

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1 Mr. Bailey is also a director of the Company.

2 The background and business experience of Jeffrey R. Bailey is incorporated by reference from the section entitled “Proposal No. 1. Election of Directors” in the Company’s Proxy Statement for the Company’s 2012 Annual Meeting of Stockholders.

From 1991 to 2006, he was employed by Ryder Scott Company in Houston performing reservoir studies including determination of oil, gas, condensate and plant product reserves, enhanced recovery and oil and gas property appraisal. For most of the period from 1978 to 1991, he worked in various petroleum engineering positions at Union Texas Petroleum Corp. in Midland and Houston, Texas, and Karachi, Pakistan and was responsible for surveillance and engineering on primary and secondary recovery projects as well as design and field supervision of workovers, pressure-transient tests and completions both onshore and offshore. During that time period he also worked for Global Natural Resources from 1983 to 1986 as senior operations engineer responsible for all engineering activities. From 1981 to 1983 he was employed by Belco Petroleum performing reservoir engineering duties including field studies, economic evaluation, reserves estimation, and initiating major field studies on waterflood projects in southwestern Wyoming and West Texas. Mr. McInturff was employed by Exxon Co. USA from 1975 to 1978 primarily with the reservoir engineering group in Midland, Texas performing drilling engineering duties including cost estimation, AFE preparation, drilling programs and field supervision. He was responsible for the surveillance of fifteen Permian Basin oil and gas fields in west Texas using both primary and secondary recovery techniques. On December 18, 2007, he was appointed to serve as Vice-President of the Company.

Cary V. Sorensen is 63 years old. He is a 1976 graduate of the University of Texas School of Law and has undergraduate and graduate degrees from North Texas State University and Catholic University in Washington, D.C. Prior to joining the Company in July 1999, he had been continuously engaged in the practice of law in Houston, Texas relating to the energy industry since 1977, both in private law firms and a corporate law department, serving for seven years as senior counsel with the oil and gas litigation department of a Fortune 100 energy corporation in Houston before entering private practice in June, 1996. He has represented virtually all of the major oil companies headquartered in Houston as well as local distribution companies and electric utilities in a variety of litigated and administrative cases before state and federal courts and agencies in nine states. These matters involved gas contracts, gas marketing, exploration and production disputes involving royalties or operating interests, land titles, oil pipelines and gas pipeline tariff matters at the state and federal levels, and general operation and regulation of interstate and intrastate gas pipelines. He has served as General Counsel of the Company since July 9, 1999.

Michael J. Rugen is 51 years old and was named Chief Financial Officer of the Company in September 2009. He is a certified public accountant (Texas) with over 29 years of experience in exploration and production and oilfield service. Prior to joining the Company, Mr. Rugen spent 2 years as Vice President of Accounting and Finance for Nighthawk Oilfield Services. From 2001 to June 2007, he was a Manager/Sr. Manager with UHY Advisors, primarily responsible for managing internal audit and Sarbanes-Oxley 404 engagements for various oil and gas clients. In 1999 and 2000, Mr. Rugen provided finance and accounting consulting services with Jefferson Wells International. From 1982 to 1998, Mr. Rugen held various accounting and management positions at BHP Petroleum, with accounting responsibilities for onshore and offshore US operations as well as operations in Trinidad and Bolivia. Mr. Rugen earned a Bachelor of Science in Accounting in 1982 from Indiana University.

Code of Ethics

The Company's Board of Directors has adopted a Code of Ethics that applies to the Company's financial officers and executives officers, including its Chief Executive Officer and Chief Financial

Officer. The Company's Board of Directors has also adopted a Code of Conduct and Ethics for Directors, Officers and Employees. A copy of these codes can be found at the Company's internet website at www.tengasco.com. The Company intends to disclose any amendments to its Codes of Ethics, and any waiver from a provision of the Code of Ethics granted to the Company's President, Chief Financial Officer or persons performing similar functions, on the Company's internet website within five business days following such amendment or waiver. A copy of the Code of Ethics can be obtained free of charge by writing to Cary V. Sorensen, Secretary, Tengasco, Inc., 11121 Kingston Pike, Suite E, Knoxville, TN 37934.

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. 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, the current global recession, and 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, 2011, the outstanding principal amount of the Company's indebtedness to F&M Bank & Trust Company ("F&M Bank") was approximately $11.5 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.

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 lenders' 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.

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. For example, during 2008, the price for oil

was extremely volatile. In July 2008, the price of oil received which had reached a record high of $147 per barrel had declined to approximately $35 per barrel by December 2008. During 2009, oil prices received ranged from a low of $34 per barrel in February 2009 to a high of $81 per barrel in October 2009. During 2010 oil prices received ranged from a low of $65 per barrel in May 2010 to a high of $91 per barrel in December 2010. During 2011, oil prices received ranged from a low of $79 per barrel in October 2011 to a high of $103 per barrel in April 2011. 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.

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 has an accumulated deficit of $25.6 million as of December 31, 2011. In 2009, the Company recorded a net loss of $2.0 million. In 2010, the Company had a profit before pipeline impairment of $1.3 million, but due to a non-cash pipeline impairment of $5 million ($3.0 million net of tax effects) the Company recorded a net loss of $1.7 million. The Company also recorded a $0.6 million non-cash unrealized gain on derivatives ($0.4 million net of tax effects). Net of both the non-cash impairment and the non-cash unrealized gain on derivatives the Company would have recorded an adjusted net income of $0.9 million. In 2011, the Company recorded net income of $4.7 million. 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 and Tennessee oil and natural gas 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.

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. In addition, 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 reserve estimates or 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 is particularly so if the price of oil declines sharply as it did during the period from mid-2008 through January 2009.

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 or of gas, or both, may be materially revised downward from time to time. As an example, the Company's proved Swan Creek gas reserves calculation has been revised downward in the past as a result of removal of portions of the Company's reported gas reserves from the "proved undeveloped category" ("PUD") and the "proved developed nonproducing" ("PDNP") categories. This downward revision was based on the Company's determination that additional drilling or development of Swan Creek may not occur in the foreseeable future because the economic returns from such drilling or development would not be favorable when compared to the costs and anticipated results of such activity. Although that particular revision at this time will not have a significant impact on overall results of operations in view of the relatively small portion of the Company's current business and assets founded in Swan Creek, other future revisions in oil and gas reserves, may be significant and materially reduce oil or gas reserves.

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.

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 Pipeline or Methane Facilities.

The Company's Pipeline and Methane facility assets are 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. During 2010, the Company incurred a writedown of its pipeline asset net of tax effect in the amount of $3.0 million. This writedown resulted from the Company's assessment that cash flows generated from the pipeline were insufficient to recover the pipeline's net book value. During the fourth quarter of 2010, the Company received expressions of interest from potential purchasers of the pipeline asset which were significantly below the asset's pre-writedown net book value of $12 million. These expressions of interest indicated that the carrying amount of the pipeline may not be recoverable. The current carrying value of the pipeline asset is approximately $6.9 million.

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

At December 31, 2011, 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.

Shortages of Oil Field Equipment, Services and 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 and as a result the demand for rigs and equipment when oil prices have risen and as a result 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.

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 and natural gas and the Company's transportation and other activities 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 Operations from Non-conventional Reserves Involve Substantial Cost and are Subject to Various Economic, Operational, and Regulatory Risks.

The Company's operations in projects involving the extraction of methane gas from non-conventional reserves such as landfill gas streams, require investment of substantial capital and are 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. These projects are 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. These projects are 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.

The Company's methane extraction business is the subject of a patent granted to the Company. There can be no assurance that our existing patent will not be invalidated, circumvented or challenged, or that patents will be issued for 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 a continuation U.S. patent application pending 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 patents will be issued for our continuation patent pending, 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 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.

Jeffrey R. Bailey, the Company's Chief Executive Officer, other 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, petrophysical analysis, and well completion design. To the extent that their services become unavailable, the Company would be required to retain other and additional qualified personnel to perform these multiple services in several 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 or retention agreements for any of the Company's key employees.

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 Amex 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 Owns 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") which is the Company's largest shareholder. At December 31, 2011, Mr. Salas directly and through Dolphin owned 21,057,492 shares of the Company's common stock and had options granting him the right to acquire an additional 118,750 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.

As of March 16, 2012 the Company had 60,737,413 shares of common stock outstanding of which 22,482,712 shares were held by affiliates. In addition, options to purchase 1,496,000 shares of unissued common stock were granted under the Tengasco, Inc. Stock Incentive Plan of which options to purchase 1,256,000 shares were vested at March 16, 2012.

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 Amex, 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.

General

The Company leases its principal executive offices, consisting of approximately 6,134 square feet located at 11121 Kingston Pike, Suite E, Knoxville, Tennessee at a rental of $7,294 per month and an office in Hays, Kansas at a rental of $750.00 per month.

Although the Company does not pay taxes on its Swan Creek leases, it pays ad valorem taxes on its Kansas Properties. The Company has general liability insurance for its Kansas and Tennessee Properties. As of December 31, 2011, the Company does not have a production interest in Texas or Louisiana.

Kansas Properties

The Kansas Properties as of December 31, 2011 contained 149 leases totaling approximately 21,720 gross acres in the vicinity of Hays, Kansas.

In 2011, the Company continued to focus on retaining properties with geologic value. Many of these leases are still in effect because they are being held by production. These leases provide for a 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 older wells and any undrilled acreage in

Kansas. The primary term for most of the Company's newer leases in Kansas is from three to five years from the date of the lease.

During 2011, the Company drilled and completed as producers 16 wells, and also drilled 9 dry holes in Kansas.

Kansas as a whole is of major significance to the Company. The majority of the Company's current reserve value, current production, revenue, and future development objectives are centered in the Company's ongoing interests in Kansas. By using 3-D seismic evaluation on existing locations owned by the Company in Kansas, the Company has added and continues to add proven direct offset locations. As a whole, our collective central Kansas holdings (see map below) are of major significance and as a group the most materially important segment of the Company as Kansas accounted for 96% of the Company's revenue (i.e. $16.4 million of $17.1 million) and 96% of the Company's total oil and gas production during 2011.

The map below indicates the location of the 10 counties in Kansas in which the Company had production as of December 31, 2011.

Tennessee Properties

The Company’s Swan Creek leases are on approximately 9,098 gross acres in Hancock and Claiborne Counties in Tennessee. At this time, all of the Company’s Tennessee production is from Hancock County.

Reserve and Production Summary

The following tables indicate the county breakdown of 2011 production and reserve values as of December 31, 2011.

Production by Area

Area	Gross Production MBOE	Average Net Revenue Interest	Percentage of Total Oil Production
Rooks County, KS	155.1	0.825382	62%
Trego County, KS	35.4	0.801299	14%
Graham County, KS	13.5	0.874067	5%
Ellis County, KS	10.4	0.832547	4%
Barton County, KS	6.9	0.818627	3%
Russell County, KS	6.2	0.855553	3%
Pawnee County, KS	4.8	0.815185	2%
Rush County, KS	3.2	0.872502	1%
Osborne County, KS	2.7	0.700066	1%
Stafford County, KS	2.6	0.717433	1%
Total KS	240.8		96%
Hancock County, TN	10.8	0.745481	4%
Total	251.6		100%

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

Area	Proved Developed	Proved Undeveloped	Proved Reserves	% of Total
Rooks County, KS	$29,956	$11,519	$41,475	59%
Trego County, KS	8,825	1,232	10,057	15%
Ellis County, KS	2,252	-	2,252	3%
Barton County, KS	2,018	1,295	3,313	5%
Graham County, KS	2,207	3,861	6,068	9%
Rush County, KS	969	-	969	1%
Stafford County, KS	211	-	211-	
Russell County, KS	1,417	-	1,417	2%
Pawnee County, KS	379	843	1,222	2%
Osborne County, KS	232	415	647	1%
Total KS	48,466	19,165	67,631	97%
Hancock County, TN	2,132	-	2,132	3%
Total	$50,598	$19,165	$69,763	100%

Reserve Analyses

The Company’s estimated total net proved reserves of oil and natural gas as of December 31, 2011 and 2010, 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, 2011

	Producing	Non Producing	Undeveloped	Total
Natural gas (MMcf)	3.7	-	-	3.7
Oil (MBbls)	1,838.1	100.7	651.9	2,590.7
Total (MBOE)	1,838.7	100.7	651.9	2,591.3
Future net cash flows before income taxes discounted at 10% (in thousands)	$ 46,621	$ 3,977	$ 19,165	$ 69,763

Total Proved Reserves as of December 31, 2010

	Producing	Non-producing	Undeveloped	Total
Natural gas (MMcf)	27.2	-	-	27.2
Oil (MBbl)	1,554.3	245.4	696.0	2,495.7
Total proved reserves (MBOE)	1,558.8	245.4	696.0	2,500.2
Future net cash flows before income taxes discounted at 10% (in thousands)	$28,987	$7,476	$11,881	$48,344

Historically, all drilling has primarily been funded by cash flows from operations. During 2011, approximately 140 MBbl of proved undeveloped reserves that existed at December 31, 2010 were converted into proved developed reserves from drilling and completion. All proved undeveloped reserves included in the Company's report at December 31, 2011 and 2010 related to oil prospects in Kansas. During 2010, 127 MBbl of proved undeveloped reserves were converted into proved developed reserves.

The oil and natural gas prices after basis adjustments used in our December 31, 2011 reserve valuation were $88.53 per Bbl and $4.16 per Mcf. The oil and natural gas prices after basis adjustments used in our December 31, 2010 reserve valuation were $72.30 per Bbl and $4.89 per Mcf. The per Bbl increase in oil price, identification of additional proved undeveloped locations, and drilling and completion of wells not included in 2010 reserve volumes were the primary factors in the increased 2011 reserve volumes and values as compared to 2010 levels. (Refer to Note 23, Supplemental Oil and Gas Information, Standardized Measure of Discounted Future Net Cash Flows for additional reserve information.)

The prices used in calculating the estimated future net revenue attributable to proved reserves do not reflect market prices for natural gas and oil production sold subsequent to December 31, 2011. 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. The net reserve values in the Report were adjusted to take into account the working interests that have been sold by the Company in various wells.

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 CEO and the Vice President responsible for management of Hoactzin's properties located onshore Texas Gulf Coast and offshore Texas/Louisiana each have extensive professional engineering experience evaluating both domestic and international 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 and compares the final report from LaRoche with the Company's in-house reserve calculations and discusses any differences with LaRoche.

Production

The following tables summarize for the past three fiscal years the volumes of oil and gas produced, the Company's operating costs and the Company's average sales prices for its oil and gas. The information includes volumes produced to royalty interest or other parties' working interest.

Kansas

Years Ended December 31,	Gross Production		Net Production		Cost of Production (per BOE)	Average Sales Price	
	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)		Oil (Bbl)	Gas (Per Mcf)
2011	240.8	-	185.7	-	$ 18.31	$ 88.15	-
2010	224.2	-	169.5	-	$ 17.33	$ 72.14	-
2009	216.7	-	166.1	-	$ 14.61	$ 54.48	-

Tennessee

Years Ended December 31,	Gross Production		Net Production		Cost of Production (per BOE)	Average Sales Price	
	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)		Oil (Bbl)	Gas (Per Mcf)
2011	5.4	32.7	3.8	25.8	$ 46.37	$ 87.33	$ 4.28
2010	6.2	59.6	4.2	24.7	$ 32.62	$ 71.05	$ 4.90
2009	5.8	78.0	4.8	73.1	$ 24.60	$ 54.87	$ 3.99

Oil and Gas Drilling Activities

Kansas

In 2011, the Company drilled 16 successful wells, and 9 dry holes. The successful wells drilled in Kansas in 2011 contributed approximately 16 MBbl of production. The Company has a 100% working interest in each of these successful wells. The Company continues to pursue incremental production increases where possible in the older wells, by using recompletion techniques to enhance production from currently producing intervals. During 2011, the Company polymered 15 wells which contributed approximately 32 MBbl of production.

Tennessee

In 2011 the Company did not drill any new wells in the Swan Creek Field. The Company believes that drilling new gas wells in the Swan Creek Field itself will not contribute to achieving any significant increase in daily gas production totals from the Field. As a result, the Company does not have any plans at the present time to drill any new gas wells in the Swan Creek Field. However, the Company does plan to continue to evaluate oil prospects in Swan Creek. During 2011, the Company drilled one unsuccessful well in the Devonian Shale. Although this was dry, the Company continues to evaluate nearby properties for the purpose of exploring the rim of the Swan Creek anticline for Devonian Shale gas production.

Gross and Net Wells

The following tables set forth the fiscal years ending December 31, 2011, 2010 and 2009 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,					
	2011		2010		2009	
Kansas	Gross	Net	Gross	Net	Gross	Net
Productive Wells	16	16	5	5	-	-
Dry Holes	9	9	5	4	-	-
Salt Water Disposal	-	-	-	-	1	1
Tennessee						
Dry Holes	1	1	-	-	-	-

Productive Wells

The following table sets forth information regarding the number of productive wells in which the Company held a working interest as of December 31, 2011. Productive wells are either producing wells or wells capable of commercial production although currently shut-in. One or more completions in the same bore hole are counted as one well.

	Gas		Oil	
	Gross	Net	Gross	Net
Kansas	-	-	205	198
Tennessee	12	11	4	3
Total	12	11	209	201

Developed and Undeveloped Oil and Gas Acreage

As of December 31, 2011 the Company owned working interests in the following developed and undeveloped oil and gas acreage. Net acres refer to the Company's interest less the interest of royalty and other working interest owners.

	Developed		Undeveloped	
	Gross Acres	Net Acres	Gross Acres	Net Acres
Kansas	13,891	11,113	7,829	6,655
Tennessee	3,120	2,340	5,978	5,231
Total	17,011	13,453	13,807	11,886

The following table identifies the number of gross and net undeveloped acres as of December 31, 2011 that will expire, by year, unless production is established before lease expiration or unless the lease is renewed.

	Kansas		Tennessee		Total	
	Gross	Net	Gross	Net	Gross	Net
2012	3,520	2,992	100	88	3,620	3,080

2013	1,000	850	1,614	1,412	2,614	2,262
2014	3,309	2,813	-	-	3,309	2,813
2015	-	-	350	306	350	306
2016	-	-	3,914	3,425	3,914	3,425
Total	7,829	6,655	5,978	5,231	13,807	11,886

ITEM 3. LEGAL PROCEEDINGS

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

ITEM 4. MINE SAFETY DISCLOSURES.

Not Applicable.

PART II

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

Market Information

The Company's common stock is listed on the NYSE Amex exchange under the symbol TGC. The range of high and low sales prices for shares of common stock of the Company as reported on the NYSE Amex during the fiscal years ended December 31, 2011 and December 31, 2010 are set forth below.

	High	Low
For the Quarters Ending		
March 31, 2011	$ 1.50	$ 0.60
June 30, 2011	$ 1.21	$ 0.64

September 30, 2011	$ 0.98	$ 0.63
December 31, 2011	$ 0.93	$ 0.65
March 31, 2010	$ 0.52	$ 0.42
June 30, 2010	$ 0.56	$ 0.41
September 30, 2010	$ 0.41	$ 0.49
December 31, 2010	$ 0.65	$ 0.41

Holders

As of March 16, 2012, the number of shareholders of record of the Company's common stock was 276 and management believes that there are approximately 8,004 beneficial owners of the Company's common stock.

Dividends

The Company did not pay any dividends with respect to the Company's common stock in 2011 or 2010 and has no present plans to declare any dividends with respect to its common stock.

Recent Sales of Unregistered Securities

During the fourth quarter of fiscal 2011, the Company did not sell or issue any unregistered securities. Any unregistered equity securities that were sold or issued by the Company during the first three quarters of fiscal 2011 were previously reported in Reports filed by the Company with the SEC.

Purchases of Equity Securities by the Company and Affiliated Purchasers

Neither the Company nor any of its affiliates repurchased any of the Company's equity securities during 2011.

Equity Compensation Plan Information

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

ITEM 6. SELECTED FINANCIAL DATA

The following selected financial data have been derived from the Company's financial statements, and should be read in conjunction with those financial statements, including the related footnotes. (In thousands, except per share data)

Years Ended December 31,	2011	2010	2009	2008	2007
Income Statement Data:					
Revenues	$17,085	$13,216	$ 9,731	$ 15,601	$ 9,369
Production Cost and Taxes	6,204	6,020	5,315	5,888	4,323
General and Administrative	2,324	2,294	2,085	2,168	1,417
Interest Expense	642	659	634	608	333
Net Income (Loss)	4,680	(1,745)	(2,018)	170	3,510
Net Income (Loss) Attributable to Common Stockholders	4,680	(1,745)	(2,018)	170	3,510
Net Income (Loss) Attributable to Common Stockholders Per Share	$0.08	$ (0.03)	$ (0.03)	$ 0.00	$ 0.06

As of December 31,	2011	2010	2009	2008	2007
Balance Sheet Data:					
Working Capital Surplus (Deficit)	$ 839	$ 10	$ (95)	$ 646	$ 2,473
Oil and Gas Properties, Net	20,206	14,157	12,360	14,142	16,940
Pipeline Facilities, Net	6,865	7,041	12,397	12,380	12,917
Methane Project, Net	5,102	4,394	4,403	4,357	1,650
Total Assets	45,999	39,749	41,174	42,447	38,011
Long-Term Debt	11,694	9,564	10,062	10,052	4,316
Stockholders' Equity	$ 30,097	$ 25,224	$ 26,843	$ 28,576	$ 28,103

No cash dividends have been declared or paid by the Company for the periods presented in the above tables.

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

Results of Operations

The Company reported a net income to holders of common stock of $4.7 million or $0.08 per share in 2011 compared to a net loss to holders of common stock of $(1.7) million or $(0.03) per share in 2010 and a net loss of $(2.0) million or $(0.03) per share in 2009. The 2010 net loss was impacted by a writedown of the Company's pipeline assets in the amount of $5.0 million. The Company also recorded a $0.6 million non-cash unrealized gain on derivatives. Net of both the non-cash impairment and the non-cash unrealized gain on derivatives the Company would have recorded an adjusted net income of $0.9 million.

The Company realized revenues of $17.1 million in 2011 compared to $13.2 million in 2010 and $9.7 million in 2009. Revenues increased $3.9 million from 2010 of which $2.8 million related to a $16.01 per barrel increase in oil prices in Kansas as prices averaged $88.15 per barrel in 2011 compared to $72.14 per barrel in 2010. During 2011, increases in sales volumes primarily from drilling and polymers contributed $1.2 million in revenues over 2010 levels. These increases were partially offset by a $(0.1) million decrease in Methane Project revenues. The average price received for Kansas oil sales in 2009 was $54.48.

Gas prices received for sales of gas from the Swan Creek Field averaged $4.28 per Mcf in 2011, $4.90 per Mcf in 2010, and $3.99 per Mcf in 2009. Oil prices received for sales of oil from the Swan Creek field averaged $87.33 in 2011, $71.05 per barrel in 2010, and $54.87 per barrel in 2009.

Production costs and taxes were $6.2 million in 2011, $6.0 million in 2010, and $5.3 million in 2009. The increases in 2011 and 2010 were primarily related to increases in well repair and maintenance cost in Kansas, increased Kansas property taxes, and increased Methane Project costs.

Depreciation, depletion, and amortization for 2011 was $2.70 million, $2.63 million in 2010, and $2.57 million in 2009. These increases related primarily to higher oil and gas depletion expense.The Company's general and administrative cost was $2.3 million in 2011 and 2010 and was $2.1 million in 2009. The 2011, 2010 and 2009 cost included non-cash charges related to stock options of $ 0.2 million, $0.1 million, and $0.2 million, respectively.

Interest expense was $0.64 million in 2011, $0.66 million in 2010, and $0.63 million in 2009.

During 2011, the Company recorded a $(0.41) million loss on derivatives. The loss was comprised of a $0.45 million unrealized gain, offset by $0.86 million of settlement payments made to Macquarie Bank Limited ("Macquarie") pursuant to a hedging agreement it entered into with Macquarie in August 2009 (see, Item 7A, "Commodity Risk"). During 2010, the Company recorded a $0.5 million gain on derivatives. The gain was comprised of a $0.6 million unrealized gain partially offset by $0.1 million of settlement payments made to Macquarie. In 2009, the Company recorded a $(1.3) million unrealized loss on derivatives.

During 2010, the Company recorded a $5 million ($3.0 million net of tax effect) non-cash writedown of its pipeline asset. This writedown resulted from the Company's assessment that cash flows generated from the pipeline were insufficient to recover the pipeline's net book value. During the fourth quarter of 2010 the Company received expressions of interest from potential purchasers of the pipeline asset which were significantly below the asset's pre-writedown net book value of $12 million. These expressions of interest indicated that the carrying amount of the pipeline may not be recoverable.

The Company recorded income tax expense of $0.2 million in 2011, an income tax benefit of $1.1 million in 2010, and an income tax benefit of $0.2 million in 2009. The tax expense in 2011 was impacted by removal of the $1.7 million valuation allowance. Had this valuation allowance not been removed the Company would have recorded tax expense of $1.9 million in 2011.

Liquidity and Capital Resources

At December 31, 2011, the Company had a revolving credit facility with F&M Bank & Trust Company ("F&M Bank").

Under the credit facility, loans and letters of credit are available to the Company on a revolving basis in an amount outstanding not to exceed the lesser of $40 million or the Company's borrowing base in effect from time to time. The credit facility is secured by substantially all of the Company's producing and non-producing oil and gas properties and pipeline and the Company's Methane Project assets. The credit facility includes certain covenants with which the Company is required to comply. These covenants include leverage, interest coverage, minimum liquidity, and general and administrative coverage ratios. During 2011 and 2010, the Company was in compliance with all covenants.

On July 30, 2010, the Company and F&M Bank entered into an amendment to the credit facility which increased the borrowing base from $11 million to $14 million, set the interest rate to the greater of prime plus 0.25% or 5.25% per annum, eliminated the monthly commitment reduction, and changed the maturity date to January 27, 2012.

On February 22, 2011, the Company and F&M Bank entered into an amendment to the credit facility which increased the borrowing base from $14 million to $20 million, increased the maximum line of the Company's credit amount from $20 million to $40 million, and extended the term of the facility to January 27, 2013.

On July 14, 2011 F&M Bank reaffirmed the Company's borrowing base at $20 million.

The total borrowings outstanding under the facility at December 31, 2011 and 2010 were $11.5 million and $9.5 million respectively. The Company believes that cash flows and availability under the credit facility will allow the Company to fully fund its operations. The next borrowing base review will take place in June 2012.

Although the Company has not been required as of the date of this Report to make any payment of principal to F&M Bank under the borrowing base in effect at any time, the Company can make no assurance that in view of the conditions in the national and world economies, including the realistic possibility of low commodity prices being received for the Company's oil and gas production for extended periods, that F&M may in the future make a redetermination of the Company's borrowing base to a point below the level of the installment or other payments to F&M in such amount and at such times in order to reduce the principal of the Company's outstanding borrowing to a level not in excess of the borrowing base as it may be redetermined.

During 2011 and 2010, the Company focused on increasing its oil production and carefully used its cash flow and available credit to do so. However, the Company can make no assurance that it can continue normal operations indefinitely or for any specific period of time in the event of extended periods of low commodity prices, such as occurred in late 2008 and early 2009, or upon the occurrence of any significant downturn or losses in operations. In such event, the Company may be required to reduce costs of operations by various means, including not undertaking certain maintenance or reworking operations that may be necessary to keep some of the Company's properties in production or to seek additional working capital by additional means such as issuance of equity including preferred stock or such other means as may be considered and authorized by the Company's Board of Directors from time to time.

Net cash provided by operating activities was $8.5 million in 2011, $4.0 million in 2010, and $1.7 million in 2009. The increase in cash provided by operating activities was primarily due to higher oil prices and increased sales volumes. Cash flow provided by working capital was $0.3 million in 2011, cash flow used for working capital was $(0.3) million in 2010 and $(0.2) million in 2009.

Net cash used in investing activities was $10.4 million in 2011, $3.8 in 2010, and $1.5 million in 2009. The increases were primarily due to higher levels of drilling and polymer activity. Also, during 2011, the Company spent $0.8 million of additional capital installing an electric generator at the Methane Facility. In addition, the Company was required to make $0.86 million of derivative settlement payments to Macquarie as well as a $0.37 million payment to Cargill Incorporated ("Cargill") to purchase a $65 floor (See Item 7A. "Commodity Risk" for a discussion of the agreement with Cargill).

In 2011, $1.8 million was provided by financing activities from bank funding which was used primarily to fund drilling and polymer activities during 2011. In 2010, $0.6 million of cash was used in financing activities related primarily to the Company entering into a sweep account arrangement allowing excess cash balances to be used to temporarily pay down the credit facility, thereby, reducing overall interest cost. In 2009 no cash was provided by or used in financing activities.

Critical Accounting Policies

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

Revenue Recognition

Revenues are recognized based on actual volumes of oil and gas sold to purchasers at a fixed or determinable price, when delivery has occurred and title has transferred, and collectability is reasonably assured. Crude oil is stored and at the time of delivery to the purchasers, revenues are recognized.

Natural gas meters are placed at the customer's location and usage is billed each month. There were no material natural gas imbalances at December 31, 2011.

Full Cost Method of Accounting

The Company follows the full cost method of accounting for oil and gas property acquisition, exploration, and development activities. Under this method, all costs incurred in connection with acquisition, exploration and development of oil and gas reserves are capitalized. Capitalized costs include lease acquisitions, seismic surveys, drilling, completion, and estimated asset retirement costs. The capitalized costs of oil and gas properties, plus estimated future development costs relating to proved reserves and estimated asset retirement costs, which are not already included net of estimated salvage value, are amortized on the unit-of-production method based on total proved reserves. The Company has determined its reserves based upon reserve reports provided by LaRoche Petroleum Consultants Ltd. in 2011, 2010, and 2009. The costs of unproved properties are excluded from amortization until the properties are evaluated, subject to an annual assessment of whether impairment has occurred. The Company currently has $0.3 million in unevaluated properties as of December 31, 2011. Proceeds from the sale of oil and gas properties are accounted for as reductions to capitalized costs unless such sales cause a significant change in the relationship between costs and the estimated value of proved reserves, in which case a gain or loss is recognized.

At the end of each reporting period, the Company performs a "ceiling test" on the value of the net capitalized cost of oil and gas properties. This test compares the net capitalized cost (capitalized cost of oil and gas properties, net of accumulated depreciation, depletion and amortization and related deferred income taxes) to the present value of estimated future net revenues from oil and gas properties using an average price (arithmetic average of the beginning of month prices for the prior 12 months) and current cost discounted at 10% plus cost of properties not being amortized and the lower of cost or estimated fair value of unproven properties included in the cost being amortized (ceiling). Prior to the year ending December 31, 2009, the ceiling was calculated using the year end price.

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

The capitalized costs of oil and gas properties, plus estimated future development costs relating to proved reserves and estimated costs of plugging and abandonment, net of costs relating to proved reserves and estimated costs of plugging and abandonment, net of estimated salvage value, are amortized on the unit-of-production method based on total proved reserves. The costs of unproved properties are excluded from amortization until the properties are evaluated, subject to an annual assessment of whether impairment has occurred.

The Company's proved oil and gas reserves as of December 31, 2011 were determined by LaRoche Petroleum Consultants, Ltd. Projecting the effects of commodity prices on production, and timing of development expenditures includes many factors beyond the Company's control. The future estimates of net cash flows from the Company's proved reserves and their present value are based upon various assumptions about future production levels, prices, and costs that may prove to be incorrect over time. Any significant variance from assumptions could result in the actual future net cash flows being materially different from the estimates.

Asset Retirement Obligations

The Company's asset retirement obligations relate to the plugging, dismantling and removal of wells drilled to date. The Company follows the requirements of FASB ASC 410, "Asset Retirement Obligations and Environmental Obligations". Among other things, FASB ASC 410 requires entities to record a liability and corresponding increase in long-lived assets for the present value of material obligations associated with the retirement of tangible long-lived assets. Over the passage of time, accretion of the liability is recognized as an operating expense and the capitalized cost is depleted over the estimated useful life of the related asset. The Company's asset retirement obligations relate primarily to the plugging, dismantling and removal of wells drilled to date. The Company's calculation of Asset Retirement Obligation used a credit-adjusted risk free rate of 12%, when the original liability for wells drilled prior to 2009 was recognized. In 2009, the retirement obligations were recognized using a credit adjusted risk free rate of 8%. The retirement obligations for new wells drilled in January through July 2010 were recognized using a credit adjusted risk free rate of 6%. The retirement obligations for new wells drilled after July 2010 were recognized using a credit adjusted risk free rate of 5.25%.

The Company used an estimated useful life of wells ranging from 30-40 years and an estimated plugging and abandonment cost of $11,000 per well in Kansas and $7,500 per well in Tennessee. These costs are escalated annually using the average of the 10 year and 20 year treasury rates. At December 31, 2011 theses rates averaged 2.2%. Management continues to periodically evaluate the appropriateness of these assumptions.

Recent Accounting Pronouncements

In May 2011, the FASB issued Accounting Standards Update ("ASU") No. 2011-04 -Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS. The guidance clarifies the FASB's intent about the application of existing fair value measurement requirements and changes particular principles or requirements for measuring fair value or for disclosing information about fair value measurements. This guidance is effective during interim and annual periods beginning after December 15, 2011. Early adoption was not permitted. The Company does not believe the changes have a material impact on its results of operations or financial position.

In December 2011, the FASB issued ASU No. 2011-11 Balance Sheet (Topic 210), Disclosures about Offsetting Assets and Liabilities. This guidance requires entities to disclose both gross information and net information about both instruments and transactions eligible for offset in the statement of financial position and instruments and transaction subject to an agreement similar to a master netting arrangements. This guidance is effecting for annual reporting periods beginning on or after January 1, 2013 and interim periods within those annual periods. We are currently evaluating the impact of the change and will make the necessary disclosures when required by the guidance.

Contractual Obligations

The following table summarizes the Company's contractual obligations due by period as of December 31, 2011 (in thousands):

Contractual Obligations	Total	Year 1	Year 2	Year 3
Long-Term Debt Obligations3	$ 11,797	$ 103	$ 80	$ 11,614
Operating Lease Obligations	131	80	51	-
Estimated Interest on Long-Term Debt Obligations	1,255	605	605	45
Total	$ 13,183	$ 788	$ 736	$ 11,659

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISKS

Commodity Risk

The Company's major market risk exposure is in the pricing applicable to its oil and gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas production. Historically, prices received for oil and gas production have been volatile and unpredictable and price volatility is expected to continue. Monthly oil price realizations ranged from a low of $78.90 per barrel to a high of $103.12 per barrel during 2011. Gas prices realizations ranged from monthly low of $4.03 per Mcf to a monthly high of $7.38 per Mcf during the same period.

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

In addition, the Company has a remaining derivative agreement on a specified number of barrels of oil that currently constitutes approximately half of the Company's daily production that ends on December 31, 2012. On July 28, 2009, the Company entered into a two-year agreement on crude oil pricing applicable to a specified number of barrels of oil that then constituted approximately two-thirds of the Company's daily production. Due to increased production levels, as well as a drop in the specified monthly barrels from 9,500 to 7,375 in 2011, this number of barrels constituted less than half of the Company's average daily production at July 31, 2011. As of August 1, 2011 the "costless collar" agreement has expired, however, the Company entered into an alternative hedging arrangement described below.

3 The credit facility maturity date of January 27, 2014 is based on the March 14, 2012 amendment to the credit agreement

This "costless collar" agreement was effective August 1, 2009 through July 31, 2011 and had a $60.00 per barrel floor and $81.50 per barrel cap on a volume of 9,500 barrels per month during the period from August 1, 2009 through December 31, 2010, and 7,375 barrels per month from January 1, 2011 through July 31, 2011. The prices referenced in this agreement were WTI NYMEX. While the agreement was based on WTI NYMEX prices, the Company receives a price based on Kansas Common plus bonus, which results in a price approximately $7 per barrel less than current WTI NYMEX prices.

Under the "costless collar" agreement, no payment was made or received by the Company, as long as the settlement price was between the floor price and cap price ("within the collar"). However, if the settlement price was above the cap, the Company was required to pay the counterparty an amount equal to the excess of the settlement price over the cap times the monthly volumes hedged. If the settlement price was below the floor, the counterparty was required to pay the Company the deficit of the settlement price below the floor times the monthly volumes hedged. As of August 1 2011, the "costless collar" agreement had expired.

On June 27, 2011 the Company entered into an agreement with Cargill, for the period from August 1, 2011 through December 31, 2012. The agreement provides to the Company a $65 per barrel floor on a stated quantity of 10,000 barrels per month, which is approximately half of the Company's current production of oil. If the average price falls below $65 per barrel, then Cargill will pay to the Company the difference between $65 and the lower average price for 10,000 barrels per month in each month during when such lower average prices occur. However, unlike the "costless collar" arrangement, the Company will not have a price cap on any portion of its production volumes. The cost of the Cargill agreement to the Company, which was paid on June 27, 2011, was $2.20 per barrel per month or a total of $374,000 for the entire period of the agreement.

These agreements were primarily intended to help maintain and stabilize cash flow from operations if lower oil prices return. If lower oil prices return, the Cargill Agreement may allow the Company to maintain production levels of crude oil by enabling the Company to perform some ongoing polymer or other workover treatments on then existing producing wells in Kansas.

Interest Rate Risk

At December 31, 2011, the Company had debt outstanding of approximately $11.8 million including, as of that date, $11.5 million owed on its credit facility with F&M Bank. The interest rate on the credit facility is variable at a rate equal to the greater of prime rate plus 0.25%, or 5.25% per annum. The Company's remaining debt of $0.3 million has fixed interest rates ranging from 3.9% to 7.25%. As a result, the Company annual interest cost in 2011 fluctuated based on short-term interest rates on approximately 98% of its total debt outstanding at December 31, 2011. During 2011, the Company paid approximately $0.6 million of interest on the F&M Bank line of credit. The impact on interest expense and the Company's cash flows of a 10% increase in the interest rate on the F&M Bank credit facility would be approximately $0.1 million assuming borrowed amounts under the credit facility remained at the same amount owed as of December 31, 2011. The Company did not have any open derivative contracts relating to interest rates at December 31, 2011.

Forward-Looking Statements and Risk

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

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

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

Effective September 21, 2011, the Company elected not to retain Rodefer Moss & Co., PLLC (Rodefer Moss") as its independent registered public accounting firm and engaged Hein & Associates LLP to audit the Company's accounts for the fiscal year ended December 31, 2011. Rodefer Moss audited the Company's financial statements for the two most recent fiscal years ended December 31, 2009 and 2010 and reviewed the Company's financial statements for the subsequent interim periods through September 21, 2011.

The change of the Company's auditors, including all the information required pursuant to Item 304(a) of Regulation S-K, was reported by the Company in its Current Report on Form 8-K filed with the SEC on September 22, 2011, which report is incorporated by reference herein. Further, the information therein is also incorporated by reference from the section entitled "Proposal No. 2: Ratification of Selection of Hein & Associates LLP as Independent Auditors" in the Proxy Statement.

There were no disagreements or other events in connection with the Company's change of accountants that would be required to be reported under Item 303(b) of Regulation S-K.

ITEM 9A. CONTROLS AND PROCEDURES

The Company's Chief Executive Officer and Chief Financial Officer, and other members of management team have evaluated the effectiveness of the Company's disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)). Based on such evaluation, the Company's Chief Executive Officer and Chief Financial Officer have concluded that the Company's disclosure

controls and procedures, as of the end of the period covered by this Report, were adequate and effective to provide reasonable assurance that information required to be disclosed by the Company in reports that is files or submits under the Exchange Act, is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms.

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

Managements Annual Report on Internal Control Over Financial Reporting

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

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

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

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

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

Under the supervision and with the participation of the Company's management, including the Chief Executive Officer and the Chief Financial Officer, the Company's management conducted an evaluation of the effectiveness of the Company internal control over financial reporting as of December 31, 2011. In making this assessment, the Company's management used the criteria set forth in the framework in "Internal Control- Integrated- Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on the evaluation conducted under the framework in "Internal

Control- Integrated Framework," issued by COSO the Company's management concluded that the Company's internal control over financial reporting was effective as of December 31, 2011.

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

Changes in Internal Control Over Financial Reporting

As part of a continuing effort to improve the Company's business processes, Management is evaluating its internal controls and may update certain controls to accommodate any modifications to its business processes or accounting procedures. During 2011, the Company strengthened its internal controls related to tax by engaging a firm to provide tax services that has significant oil and gas and public company experience. There have been no other changes to the Company's system of internal control over financial reporting during the year ended December 31, 2011 that have materially affected, or are reasonably likely to materially affect, the Company's system of controls over financial reporting.

ITEM 9B. OTHER INFORMATION

The Company's 2011 Annual Meeting of Stockholders will be held on May 29, 2012 at 1:00 pm at the Homewood Suites by Hilton, 10935 Turkey Drive, Knoxville, Tennessee 37922.

On March 14, 2012, the Company's senior credit facility with F&M Bank and Trust Company, N.A. of Dallas, Texas (F&M Bank") after F&M Bank's semiannual review of the Company's currently owned producing properties was amended to increase the Company's borrowing base from $20 million to $23 million and extend the term of the facility to January 27, 2014. The borrowing base remains subject to the existing periodic redetermination provisions in the credit facility. The maximum line of credit of the Company under the F&M Bank credit facility is $40 million and the Company's outstanding borrowing under the facility as of March 14, 2012 was $14.5 million.

PART III

Certain information required by Part III of this Report is incorporated by reference from the Company's definitive proxy statement to be filed with the SEC in connection with the solicitation of proxies for the Company's 2012 Annual Meeting of Stockholders (the "Proxy Statement").

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERANCE

The information required by this Item with respect to the Company's directors is incorporated by reference to the information in the section entitled "Proposal No. 1: Election of Directors" in the Proxy Statement.

The information required by this Item with respect to corporate governance regarding the Nominating Committee and Audit Committee of the Board of Directors is incorporated by reference from the section entitled "Board of Directors-Committees" in the Proxy Statement.

The information required by this Item with respect to disclosure of any known late filing or failure by an insider to file a report required by Section 16 of the Exchange Act is incorporated by reference to the information in the section entitled "Section 16(a) Beneficial Ownership Reporting Compliance" in the Proxy Statement.

The information required by this item with respect to the identification and background of the Company's executive officers and the Company's Code of Ethics is set forth in Item 1 of this Report.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference from the information in the sections entitled "Executive Compensation", "Compensation/Stock Option Committee Interlocking and Insider Participation" and "Compensation Committee Report" in the Proxy Statement.

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

Except as set forth below, the information required by this Item regarding security ownership of certain beneficial owners and directors and officers is incorporated by reference from the sections entitled "Voting Securities and Principal Holders" and "Beneficial Ownership of Directors and Officers" in the Proxy Statement.

Equity Compensation Plan Information

The following table sets forth information regarding the Company's equity compensation plans as of December 31, 2011.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights(a)	Weighted-average exercise price of outstanding options, warrants and rights(b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders4	1,471,000	$0.61	1,956,623
Equity compensation plans not approved by security holders	-	-	-

4 Refers to Tengasco, Inc. Stock Incentive Plan (the "Plan") which was adopted to provide an incentive to key employees, officers, directors and consultants of the Company and its present and future subsidiary corporations, and to offer an additional inducement in obtaining the services of such individuals. The Plan provides for the grant to employees of the Company of "Incentive Stock Options" within the meaning of Section 422 of the Internal Revenue Code of 1986, as amended, nonqualified stock options to outside Directors and consultants the Company and stock appreciation rights. The Plan was approved by the Company's shareholders on June 26, 2001. Initially, the Plan provided for the issuance of a maximum of 1,000,000 shares of the Company's $.001 par value common stock. Thereafter, the Company's Board of Directors adopted and the shareholders approved amendments to the Plan

to increase the aggregate number of shares that may be issued under the Plan to 7,000,000 shares. The most recent amendment to the Plan increasing the number of shares that may be issued under the Plan by 3,500,000 shares and extending the Plan for another 10 years was approved by the Company Board of Directors on February 1, 2008 and approved by the Company's shareholders at the Annual Meeting of Stockholders held June 2, 2008.

Total	1,471,000	$0.61	1,956,623

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

The information required by this Item as to transaction between the Company and related persons is incorporated by reference from the section entitled “Certain Transactions” in the Proxy Statement.

The information required by this Item as to the independence of the Company’s directors and members of the committees of the Company’s Board of Directors is incorporated by reference from the section entitled “Board of Directors” and the subsections thereunder entitled “Director Independence” and “Committees” set forth in “Proposal No.1: Election of Directors” in the Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this Item is incorporated by reference from the information in the section entitled “Proposal No. 2: Ratification of Selection of Hein & Associates LLP as Independent Auditors” in the Proxy Statement.

PART IV.

ITEM 15. EXHIBITS AND FINANCIAL STATEMENTS SCHEDULES

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

1. Financial Statements:

Consolidated Balance Sheets

Consolidated Statements of Operations

Consolidated Statements of Stockholders Equity

Consolidated Statements of Cash Flows

Notes to Consolidated Financial Statements

2. Financial Schedules:

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

3. Exhibits.

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

Exhibit Index

Exhibit Number	Description
3.1	Delaware Certificate of Incorporation (Incorporated by reference to Exhibit B to registrant's Definitive Proxy Statement pursuant to Schedule 14a filed May 2, 2011).
3.2	Bylaws (Incorporated by reference to Exhibit B to registrant's Definitive Proxy Statement filed May 2, 2011).
3.3	Agreement and Plan of Merger of Tengasco, Inc. (a Tennessee corporation with and into Tengasco, Inc., a Delaware corporation dated as of April 15, 2011 (Incorporated by reference to Exhibit B to registrant's Definitive Proxy Statement pursuant to Schedule 14a filed May 2, 2011).
4.1	Form of Rights Certificate Incorporated by reference to registrant's statement on Form S-1 filed February 13, 2004 Registration File No. 333-109784 (the "Form S-1")
10.1	Natural Gas Sales Agreement dated November 18, 1999 between Tengasco, Inc. and Eastman Chemical Company (Incorporated by reference to Exhibit 10.10 to the registrant's current report on Form 8-K filed November 23, 1999)
10.2	Amendment Agreement between Eastman Chemical Company and Tengasco, Inc. dated March 27, 2000 (Incorporated by reference to Exhibit 10.14 to the registrant's 1999 Form 10-KSB)
10.3	Tengasco, Inc. Incentive Stock Plan (Incorporated by reference to Exhibit 4.1 to the registrant's registration statement on Form S-8 filed October 26, 2000)
10.4	Amendment to the Tengasco, Inc. Stock Incentive Plan dated May 19, 2005 (Incorporated by reference to Exhibit 4.2 to the registrant's registration statement on Form S-8 filed June 3, 2005)

10.5	Loan and Security Agreement dated as of June 29, 2006 between Tengasco, Inc. and Citibank Texas, N.A. (Incorporated by reference to Exhibit 10.1 to the registrant's Current Report on Form 8-K dated June 29, 2006)
10.6	Subscription Agreement of Hoactzin Partners, L.P. for the Company's ten well drilling program on its Kansas Properties dated August 3, 2007 (Incorporated by reference to Exhibit 10.15 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2007 filed March 31, 2008 [the "2007 Form 10-K"])..
10.7	Agreement and Conveyance of Net Profits Interest dated September 17, 2007 between Manufactured Methane Corporation as Grantor and Hoactzin Partners, LP as Grantee (Incorporated by reference to Exhibit 10.16 to the 2007 Form 10-K).
10.8	Agreement for Conditional Option for Exchange of Net Profits Interest for Convertible Preferred Stock dated September 17, 2007 between Tengasco, Inc., as Grantor and Hoactzin Partners, L.P., as Grantee (Incorporated by reference to Exhibit 10.17 to the 2007 Form 10-K).
10.9	Assignment of Notes and Liens Dated December 17, 2007 between Citibank, N.A., as Assignor, Sovereign Bank, as Assignee and Tengasco, Inc., Tengasco Land & Mineral Corporation and Tengasco Pipeline Corporation as Debtors (Incorporated by reference to Exhibit 10.18 to the 2007 Form 10-K).
10.10	Management Agreement dated December 18, 2007 between Tengasco, Inc. and Hoactzin Partners, L.P. (Incorporated by reference to Exhibit 10.20 to the 2007 Form 10-K).
10.11	Amendment to the Tengasco, Inc. Stock Incentive Plan dated February 1, 2008, 2008 (Incorporated by reference to Exhibit 4.1 to the registrant's registration statement on Form S-8 filed June 3, 2008)
10.12	Assignment of Leases from Black Diamond Oil, Inc. to Tengasco, Inc. (Incorporated by reference to Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2008 filed on August 11, 2008).
10.13	Energy Option Transaction Confirmation Agreement (Put) between Tengasco, Inc. and Macquarie Bank Limited dated September 17, 2009 (Incorporated by reference to Exhibit 10.13 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2009 filed on March 31, 2010).
10.14	Energy Option Transaction Confirmation Agreement (Call) Amendment between Tengasco, Inc. and Macquarie Bank Limited dated September 17, 2009 (Incorporated by reference to Exhibit 10.14 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2009 filed on March 31, 2010).
10.15	Assignment of Credit Facility to F&M Bank and Trust Company (Incorporated by reference to Exhibit 10.15 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2010 filed on March 31, 2011).

10.16	Ninth Amendment to Loan and Security Agreement dated February 22, 2011 between Tengasco, Inc. as borrower and F&M Bank Trust Company as Lender (incorporated by reference to Exhibit 9.01to the registrant's Current Report on Form 8-K filed on February 25, 2011).
10.17*	Tenth Amendment to Loan and Security Agreement dated March 14, 2012 between Tengasco, Inc. as borrower and F&M Bank Trust Company as Lender
14	Code of Ethics (Incorporated by reference to Exhibit 14 to the registrant's Annual Report on Form 10-K filed March 30, 2004)
21	List of subsidiaries (Incorporated by reference to Exhibit 21 to the 2007 Form 10-K).
23.1*	Consent of LaRoche Petroleum Consultants, Ltd.
23.2*	Consent of Rodefer Moss & Co., PLLC
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a)
32.1*	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1*	Report of LaRoche Petroleum Consultants, Ltd. has been added to the filing for the year ended December, 31, 2011
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Definition Linkbase Document
101.LAB*	XBRL Taxonomy Label Linkbase Document
101.PRE*	XBRLTaxonomy Presentation Linkbase Document

* Exhibit filed with this Report

Signatures

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

Dated: March 29, 2012

Tengasco, Inc.

(Registrant)

By: s/ Jeffrey R. Bailey

Jeffrey R. Bailey,

Chief Executive Officer

By: s/ Michael J. Rugen

Michael J. Rugen,

Principal Financial and Accounting Officer

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

Signature	Title	Date
s/ Jeffrey R. Bailey Jeffrey R. Bailey	Director; Chief Executive Officer	March 29,2012
s/ Matthew K. Behrent Matthew K. Behrent	Director	March 29,2012
s/John A. Clendening John A. Clendening	Director	March 29,2012
s/ Peter E. Salas Peter E. Salas	Director	March 29,2012
s/ Hughree F. Brooks Hughree F. Brooks	Director	March 29,2012
s/ Michael J. Rugen Michael J. Rugen	Principal and Financial Accounting Officer	March 29,2012

Tengasco, Inc.
and Subsidiaries

Consolidated Financial Statements
Years Ended December 31, 2011, 2010, and 2009

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders
Tengasco, Inc.

We have audited the accompanying consolidated balance sheet of Tengasco, Inc. and subsidiaries as of December 31, 2011, and the related consolidated statements of income, stockholders' equity, and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Tengasco, Inc. and subsidiaries as of December 31, 2011, and the results of their operations and their cash flows for the year then ended, in conformity with U.S. generally accepted accounting principles.

s/Hein & Associates LLP
Houston, Texas

March 29, 2012

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Director's and

Stockholder's of Tengasco, Inc.

We have audited the accompanying consolidated balance sheets of Tengasco, Inc. (the "Company") as of December 31, 2010 and 2009, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the years in the three-year period ended December 31, 2010. The Company's management is responsible for these consolidated financial statements. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The company was not required for 2010 to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Tengasco, Inc. as of December 31, 2010 and 2009, and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America.

s/ Rodefer Moss & Co., PLLC

Knoxville, Tennessee
March 31, 2011

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Tengasco, Inc. and Subsidiaries

Consolidated Balance Sheets

(In thousands, except per share and share data)

	December 31, 2011	2010
Assets		
Current		
Cash and cash equivalents	$ 68	$ 141
Accounts receivable	1,579	1,517
Accounts receivable-related party	265	993
Inventory	823	577
Deferred tax asset-current	164	264
Commodity derivative asset-current	142	-
Other current assets	79	42
Total current assets	3,120	3,534
Restricted cash	121	121
Loan fees, net	82	99
Oil and gas properties, net (full cost accounting method)	20,206	14,157
Pipeline facilities, net	6,865	7,041
Methane project, net	5,102	4,394
Other property and equipment, net	426	308
Deferred tax asset-noncurrent	10,077	10,095
Total assets	$ 45,999	$ 39,749

See accompanying Notes to Consolidated Financial Statements

Tengasco, Inc. and Subsidiaries

Consolidated Balance Sheets

(In thousands, except per share and share data)

	December 31, 2011	2010
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable-trade	$ 1,203	$ 550
Accounts payable other	265	993
Accrued liabilities	710	571
Prepaid revenues- current	-	594
Current maturities of long-term debt	103	129
Commodity derivative liability-current	-	687
Total current liabilities	2,281	3,524
Asset retirement obligation	1,927	1,437
Long term debt, less current maturities	11,694	9,564
Total liabilities	15,902	14,525
Stockholders' equity		
Common stock, $.001 par value: authorized 100,000,000 Shares; 60,737,413 and 60,687,413 shares issued and outstanding	61	61
Additional paid in capital	55,595	55,402
Accumulated deficit	(25,559)	(30,239)
Total stockholders' equity	30,097	25,224
Total liabilities and stockholders' equity	$ 45,999	$ 39,749

See accompanying Notes to Consolidated Financial Statements

Tengasco, Inc. and Subsidiaries

Consolidated Statements of Operations

(In thousands, except per share and share data)

	Year ended December 31,		
	2011	2010	2009
Revenues	$ 17,085	$ 13,216	$ 9,731
Cost and expenses			
Production costs and taxes	6,204	6,020	5,315
Depreciation, depletion, and amortization	2,703	2,627	2,571
General and administrative	2,324	2,294	2,085
Impairment	-	4,957	-
Total cost and expenses	11,231	15,898	9,971
Net income (loss) from operations	5,854	(2,682)	(240)
Other income (expense)			
Interest expense	(642)	(659)	(634)
Gain (loss) on derivatives	(407)	492	(1,313)
Gain (loss) on sale of assets	37	15	-
Total other income (expense)	(1,012)	(152)	(1,947)
Income (loss) before income tax	4,842	(2,834)	(2,187)
Deferred income tax benefit (expense)	(118)	1,089	169
Current income tax benefit (expense)	(44)	-	-
Net income (loss)	$ 4,680	$ (1,745)	$ (2,018)
Net income (loss) per share			
Basic	$ 0.08	$ (0.03)	$ (0.03)
Fully diluted	$ 0.08	$ (0.03)	$ (0.03)
Shares used in computing earnings per share			
Basic	60,701,660	60,415,859	59,408,990
Diluted	61,088,983	60,415,859	59,408,990

See accompanying Notes to Consolidated Financial Statements

Tengasco, Inc. and Subsidiaries

Consolidated Statements of Stockholders' Equity

(In thousands, except per share and share data)

	Common Stock		Paid-in Capital	Accumulated Deficit	Total
	Shares	Amount			
Balance, December 31, 2008	59,350,661	$ 59	$ 54,993	$ (26,476)	$ 28,576
Net loss	-	-	-	(2,018)	(2,018)
Options and compensation expense	-	-	174	-	174
Common stock issued for exercise of options	410,000	1	110	-	111
Balance, December 31, 2009	59,760,661	$ 60	$ 55,277	$ (28,494)	$ 26,843
Net loss	-	-	-	(1,745)	(1,745)
Options and compensation expense	-	-	111	-	111
Common stock issued for exercise of options	926,752	1	14	-	15
Balance, December 31, 2010	60,687,413	$ 61	$ 55,402	$ (30,239)	$ 25,224
Net income				4,680	4,680
Options and compensation expense			165		165
Common stock issued for exercise of options	50,000	-	28		28
Balance, December 31, 2011	60,737,413	$ 61	$ 55,595	$ (25,559)	$ 30,097

See accompanying Notes to Consolidated Financial Statements

Tengasco, Inc. and Subsidiaries

Consolidated Statements of Cash Flows

(In thousands)

	Year Ended December 31,		
	2011	2010	2009
Operating activities			
Net income (loss)	$ 4,680	$ (1,745)	$ (2,018)
Adjustments to reconcile net income (loss) to net cash			
Provided by operating activities			
Depreciation, depletion, and amortization	2,703	2,627	2,571
Amortization of loan fees-interest expenses	77	97	-
Accretion on asset retirement obligation	96	112	48
Impairment	-	4,957	-
(Gain) loss on sale of vehicles/equipment	(37)	(15)	-
Compensation and services paid in stock options	165	111	174
Deferred income tax expense (benefit)	118	(1,089)	(169)
(Gain) loss on derivatives	407	(626)	1,313
Changes in assets and liabilities			
Accounts receivable	(62)	(369)	(20)
Accounts receivable-related party	728	(993)	-
Inventory and other assets	(283)	(18)	(115)
Accounts payable-trade	653	(191)	41
Accounts payable- other	(728)	993	-
Accrued liabilities	139	268	(137)
Settlement on asset retirement obligations	(165)	(75)	-
Net cash provided by operating activities	8,491	4,044	1,688
Investing activities			
Additions to oil and gas properties	(8,315)	(3,533)	(1,020)
Proceeds from sale of oil and gas properties	36	-	142
Net additions to Methane Project	(811)	(69)	(184)
Net additions to pipeline facilities	-	(22)	(418)
Net additions to other property & equipment	(48)	(134)	-
Derivative costs and settlements	(1,236)	-	-
Net cash (used in) investing activities	(10,374)	(3,758)	(1,480)
Financing activities			
Proceeds from exercise of options/warrants	28	15	111
Proceeds from borrowings	2,030	-	-
Repayment of borrowings	(188)	(532)	(142)
Loan fees	(60)	(50)	-
Net cash provided by (used in) financing activities	1,810	(567)	(31)
Net change in cash and change equivalents	(73)	(281)	177
Cash and cash equivalents, beginning of period	141	422	245
Cash and cash equivalents, end of period	$ 68	$ 141	$ 422
Supplemental cash flow information:			

Interest paid	$ 565	$ 562	$ 634
Supplemental non-cash investing and financing activities:			
Financed Company vehicles	$ 262	$ 44	$ 196
Asset retirement obligations capitalized	$ 559	$ 950	$ (254)

See accompanying Notes to Consolidated Financial Statements

Tengasco, Inc. and Subsidiaries
Notes to Consolidated Financial Statements

1. Description of Business and Significant Accounting Policies

Tengasco, Inc. is a Delaware corporation ("Tengasco" or the "Company").

The Company is in the business of exploration and production of oil and natural gas. The Company's primary area of oil exploration and production is in Kansas. The Company's primary area of natural gas exploration and production is the Swan Creek Field in Tennessee.

The Company's wholly-owned subsidiary, Tengasco Pipeline Corporation ("TPC"), owns and operates 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's wholly-owned subsidiary, Manufactured Methane Corporation ("MMC") operates treatment and delivery facilities using the latest developments in available treatment technologies for the extraction of methane gas from nonconventional sources for delivery through the nations existing natural gas pipeline system, including the Company's TPC pipeline system in Tennessee for eventual sale to natural gas customers.

Principles of Consolidation

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

Use of Estimates

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

Revenue Recognition

Revenues are recognized based on actual volumes of oil and gas sold to purchasers at a fixed or determinable price, when delivery has occurred and title has transferred, and collectability is reasonably assured. Crude oil is stored and at the time of delivery to the purchasers, revenues are recognized.

Natural gas meters are placed at the customer's location and usage is billed each month. There were no material natural gas imbalances at December 31, 2011.

Cash and Cash Equivalents

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

Restricted Cash

As security required by Tennessee oil and gas regulations, the Company placed $120,500 in a Certificate of Deposit to cover future asset retirement obligations for the Company's Tennessee wells.

Inventory

Inventory consists of crude oil in tanks and is carried at lower of cost or market value. In addition, the Company also carried equipment and materials to be used in its Kansas operation and is carried at lower of cost or market value. At December 31, 2011 and 2010, inventory consisted of the following (in thousands):

	December 31,	
	2011	2010
Oil	$ 679	$ 566
Equipment and materials	144	11
	$ 823	$ 577

Oil and Gas Properties

The Company follows the full cost method of accounting for oil and gas property acquisition, exploration, and development activities. Under this method, all costs incurred in connection with acquisition, exploration and development of oil and gas reserves are capitalized. Capitalized costs include lease acquisitions, seismic surveys, drilling, completion, and estimated asset retirement costs. The capitalized costs of oil and gas properties, plus estimated future development costs relating to proved reserves and estimated asset retirement costs, which are not already included net of estimated salvage value, are amortized on the unit-of-production method based on total proved reserves. The Company has determined its reserves based upon reserve reports provided by LaRoche Petroleum Consultants Ltd. in 2011, 2010, and 2009. The costs of unproved properties are excluded from amortization until the properties are evaluated, subject to an annual assessment of whether impairment has occurred. The Company has $0.3 million in unevaluated properties as of December 31, 2011. Proceeds from the sale of oil and gas properties are accounted for as reductions to capitalized costs unless such sales cause a significant change in the relationship between costs and the estimated

value of proved reserves, in which case a gain or loss is recognized.

At the end of each reporting period, the Company performs a “ceiling test” on the value of the net capitalized cost of oil and gas properties. This test compares the net capitalized cost (capitalized cost of oil and gas properties, net of accumulated depreciation, depletion and amortization and related deferred income taxes) to the present value of estimated future net revenues from oil and gas properties using an average price (arithmetic average of the beginning of month prices for the prior 12 months) and current cost discounted at 10% plus cost of properties not being amortized and the lower of cost or estimated fair value of unproven properties included in the cost being amortized (ceiling). Prior to the year ending December 31, 2009, the ceiling was calculated using the year end price.

Asset Retirement Obligation

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

Pipeline Facilities

The pipeline was placed into service in 2001. The pipeline is being depreciated over its estimated useful life of 30 years. The Company reviews the carrying value of the pipeline for impairment whenever events and circumstances indicate that the carrying value of an asset may not be recoverable from the estimated future cash flows expected to result from its use and eventual disposition. In cases where undiscounted expected future cash flows are less than the carrying value, an impairment loss is recognized equal to an amount by which the carrying value exceeds the fair value of assets. The factors considered by management in performing this assessment include current operating results, trends, and prospects, as well as the effects of obsolescence, demand, competition, and other economic factors. During 2010 there were indicators the pipeline may be impaired and the Company performed an assessment of the carrying value as of December 31, 2010 based on expected future cash flows. The assessment resulted in the Company recording an impairment of approximately $5.0 million for the year ended December 31, 2010. At December 31, 2011 management determined there were no indicators of impairment, therefore, there is no impairment charge for the year ended December 31, 2011. The net book value of the pipeline system was approximately $6.9 million and $7.0 million at December 31, 2011 and 2010, respectively. The Company recorded depreciation expense of $0.2 million, $0.4 million and $0.4 million for the years 2011, 2010, and 2009, respectively.

Tengasco, Inc. and Subsidiaries
Notes to Consolidated Financial Statements

Manufactured Methane Facilities

The methane facilities were placed into service on April 1, 2009. The methane facilities are being depreciated over an estimated useful life of 32 years and 9 months beginning at the time it was placed in service. This useful life is based on estimated landfill closure date of December 2041. The Company recorded depreciation expense of $0.1 million in each of the years 2011, 2010, and 2009.

Other Property and Equipment

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

Stock-Based Compensation

The Company records stock-based compensation to employees based on the estimated fair value of the award at grant date. We recognize expense on a straight line basis over the requisite service period. The Company recorded compensation expense of $0.2 million in 2011, $0.1 million in 2010 and $0.2 million in 2009.

Accounts Receivable

Accounts receivable consist of uncollateralized joint interest owner obligations due within 30 days of the invoice date and uncollateralized accrued revenues due under normal trade terms, generally requiring payment within 30 days of production. No interest is charged on past-due balances. Payments made on accounts receivable are applied to the earliest unpaid items. We review accounts receivable periodically and reduce the carrying amount by a valuation allowance that reflects our best estimate of the amount that may not be collectible. No such allowance was considered necessary at December 31, 2011 or 2010.

Income Taxes

Income taxes are reported in accordance with U.S. GAAP, which requires the establishment of deferred tax accounts for all temporary differences between the financial reporting and tax bases of assets and liabilities, using currently enacted federal and state income tax rates. In addition, deferred tax accounts must be adjusted to reflect new rates if enacted into law. Temporary differences result principally from federal and state net operating loss carryforwards, differences in oil and gas property values resulting from a 2008 ceiling test write down, differences in pipeline values resulting from a 2010 impairment, and differences in methods of reporting depreciation and amortization. Management routinely assesses the ability to realize our deferred tax assets and reduces such assets by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be recognized.

Tengasco, Inc. and Subsidiaries
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At December 31, 2011, federal net operating loss carryforwards amounted to approximately $16.2 million which expire between 2013 and 2024. The total deferred tax asset was $10.2 million and $10.4 million at December 31, 2011 and 2010, respectively.

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

Management periodically evaluates tax reporting methods to determine if any uncertain tax positions exist that would require the establishment of a loss contingency. A loss contingency would be recognized if it were probable that a liability has been incurred as of the date of the financial statements and the amount of the loss can be reasonably estimated. The amount recognized is subject to estimates and management's judgment with respect to the likely outcome of each uncertain tax position. The amount that is ultimately incurred for an individual uncertain tax position or for all uncertain tax positions in the aggregate could differ from the amount recognized.

Although management considers our valuation allowance and loss contingency as of December 31, 2011 and 2010 adequate, material changes in these amounts may occur in the future based on tax audits and changes in legislation.

Concentration of Credit Risk

Financial instruments which potentially subject the Company to concentrations of credit risk consist principally of cash and accounts receivable. Cash and cash equivalents are maintained at financial institutions and, at times, balances may exceed federally insured limits. We have never experienced any losses related to these balances. All of our non-interest bearing cash balances were fully insured at December 31, 2011 due to a temporary federal program in effect from December 31, 2010 through December 31, 2012. Under the program, there is no limit to the amount of insurance for eligible accounts. Beginning 2013, insurance coverage will revert to $250,000 per depositor at each financial institution, and our non-interest bearing cash balances may again exceed federally insured limits.

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

The Company sells a majority of its crude oil primarily to one customer in Tennessee and two customers in Kansas. Additionally, the Company is presently dependent upon a small number of customers for the sale of gas from the Swan Creek Field. Although management believes that customers could be replaced in the ordinary course of business, if the present

Tengasco, Inc. and Subsidiaries
Notes to Consolidated Financial Statements

customers were to discontinue business with the Company, it may have a significant adverse effect on the Company's projected results of operations.

Revenue from the top three purchasers accounted for 83.5%, 13.9%, and 1.9% of total oil and gas revenues for year ended December 31, 2011. Revenue from the top three purchasers accounted for 80.0%, 16.6% and 2.3% of total oil and gas revenues for the year ended December 31, 2010. Revenue from the top three purchasers accounted for 85.1%, 10.5% and 3.1% of total oil and gas revenues for the year ended December 31, 2009.

Earnings per Common Share

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

	For the years ended December 31,		
	2011	2010	2009
Income (numerator):			
Net income (loss)	$ 4,680	$ (1,745)	$ (2,018)
Weighted average shares (denominator):			
Weighted average shares - basic	60,701,660	60,415,859	59,408,990
Dilution effect of share-based compensation, treasury method[5]	387,323	-	-
Weighted average shares - dilutive	61,088,983	60,415,859	59,408,990
Earnings (loss) per share:			
Basic	$ 0.08	$ (0.03)	$ (0.03)
Dilutive	$ 0.08	$ (0.03)	$ (0.03)

Fair Value of Financial Instruments

The carrying amounts of financial instruments including cash and cash equivalents, accounts receivable, accounts payables, accrued liabilities and long term debt approximates fair value as of December 31, 2011 and 2010. (See Note 10 Derivatives for commodity derivative fair value disclosures)

Derivative Financial Instruments

The Company uses derivative instruments to manage our exposure to commodity price risk on sales of oil production. The Company does not enter into derivative instruments for speculative trading purposes. The Company presents the fair value of derivative contracts on a

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5 Because the Company had net losses for the years ended December 31, 2010 and 2009, dilutive potential shares of common stock were excluded as they were anti-dilutive.

net basis where the right to offset is provided for in our counterparty agreements. (See Note 10 Derivatives)

Reclassifications

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

2. Recent Accounting Pronouncements

In May 2011, the FASB issued Accounting Standards Update ("ASU") No. 2011-04 -Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS. The guidance clarifies the FASB's intent about the application of existing fair value measurement requirements and changes particular principles or requirements for measuring fair value or for disclosing information about fair value measurements. This guidance is effective during interim and annual periods beginning after December 15, 2011. Early adoption was not permitted. The Company does not believe the changes have a material impact on its results of operations or financial position.

In December 2011, the FASB issued ASU No. 2011-11 Balance Sheet (Topic 210), Disclosures about Offsetting Assets and Liabilities. This guidance requires entities to disclose both gross information and net information about both instruments and transactions eligible for offset in the statement of financial position and instruments and transaction subject to an agreement similar to a master netting arrangements. This guidance is effecting for annual reporting periods beginning on or after January 1, 2013 and interim periods within those annual periods. We are currently evaluating the impact of the change and will make the necessary disclosures when required by the guidance.

3. Related Party Transactions

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

Under the terms of the Ten Well Program, Hoactzin paid the Company $0.4 million for each well drilled in the Ten Well Program completed as a producing well and $0.25 million for each well that was non-productive. The terms of the Ten Well Program also provide that Hoactzin will receive all the working interest in the ten wells in the Program, but will pay an initial fee to the Company of 25% of its working interest revenues net of operating expenses. This is referred to as a management fee but, as defined, is in the nature of a net profits interest.

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The fee paid to the Company by Hoactzin will increase to 85% when and if net revenues received by Hoactzin reach an agreed payout point of approximately 1.35 times Hoactzin's purchase price (the "Payout Point") for its interest in the Ten Well Program.

In March 2008, the Company drilled and completed the tenth and final well in the Ten Well Program. Of the ten wells drilled, nine were completed as oil producers and are currently producing approximately 38 barrels per day in total. Hoactzin paid a total of $3.85 million (the "Purchase Price") for its interest in the Ten Well Program resulting in the Payout Point being determined as $5.2 million. The amount paid by Hoactzin for its interest in the Program wells exceeded the Company's actual drilling costs of approximately $2.8 million for the ten wells by more than $1 million.

Under the terms of the Company's agreement with Hoactzin, reaching the Payout Point may be accelerated by operation of a second agreement by which Hoactzin will apply 75% of the net profits it may receive from a methane extraction project discussed below developed by the Company's wholly-owned subsidiary, Manufactured Methane Corporation ("MMC"), to the Payout Point. However, as discussed below, although the Methane Project has been placed into operation, no Methane Project net profits have been generated or paid to Hoactzin through December 31, 2011.

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

Through December 31, 2011, no payments have been made to Hoactzin for its 75% net profits interest in the Methane Project, because no net profits have been generated. The method of calculation of the net profits interest takes into account specific costs and expenses as well as gross revenues for the project. As a result of the startup costs and ongoing operating expenses, no net profits, as defined in the agreement, have been generated from project startup in April, 2009 through December 31, 2011 for payment to Hoactzin under the net profits interest conveyed. When the Payout Point is reached from either the revenues from the wells drilled in the Ten Well Program or Hoactzin's share of the net profits from the Methane Project or a combination thereof, Hoactzin's net profits interest in the Methane Project will decrease to a 7.5% net profits interest.

On September 17, 2007, the Company also entered into a third simultaneous agreement with Hoactzin providing that if the Program and the Methane Project interest in combination failed to return net revenues to Hoactzin equal to 25% of the Purchase Price it paid for its interest in the Ten Well Program by December 31, 2009, then Hoactzin would have an option to exchange up to 20% of its net profits interest in the Methane Project for convertible preferred stock to be issued by the Company with a liquidation value equal to 20% of the Purchase Price less the net proceeds received at the time of any exchange. By December 31, 2011, the amount of net revenues received by Hoactzin from the Ten Well Program has reduced the Company's obligation to Hoactzin for the amount of the funds it had advanced for the Purchase Price from $3.85 million to zero, thereby reaching the purchase price and therefore no preferred stock will ever be issued to Hoactzin.

On December 18, 2007, the Company entered into a Management Agreement with Hoactzin. On that same date, the Company also entered into an agreement with Charles Patrick McInturff employing him as a Vice-President of the Company. Pursuant to the Management Agreement with Hoactzin, Mr. McInturff's duties while he is employed as Vice-President of the Company will include the management on behalf of Hoactzin 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 consideration for the Company entering into the Management Agreement, Hoactzin agreed that it will be responsible to reimburse the Company for the payment of one-half of Mr. McInturff's salary, as well as certain other benefits he receives during his employment by the Company. In further consideration for the Company's agreement to enter into the Management Agreement, Hoactzin granted to the Company an option to participate in up to a 15% working interest on a dollar for dollar cost basis in any new drilling or workover activities undertaken on Hoactzin's managed properties during the term of the Management Agreement. The term of the Management Agreement ends on the earlier of the date Hoactzin sells its interest in its managed properties or five years (December 2012).

The Company became the operator of certain properties owned by Hoactzin in connection with the Management Agreement. 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 both the Bureau of Ocean Energy Management, Regulation and Enforcement, and certain private parties.

In connection with the issuance of these bonds the Company entered into a Payment and Indemnity Agreement with IndemCo whereby the Company guarantees payment of any bonding liabilities incurred by IndemCo. Dolphin Direct Equity Partners, LP co-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.

As operator, the Company has routinely contracted in its name for goods and services with vendors in connection with its operation of the Hoactzin properties. In practice, Hoactzin pays directly these invoices for goods and services that are contracted in the Company's name. During late 2009 and early 2010, Hoactzin undertook several significant operations, for which the Company contracted in the ordinary course. As a result of the operations performed in late 2009 and early 2010, Hoactzin currently has significant past due balances to several vendors, a portion of which are included on the Company's balance sheet. Payables related to these and ongoing operations remained outstanding at the end of 2011 and 2010 in the amount of $0.3 million and $1.0 million respectively. Because this amount is material, the Company has recorded the Hoactzin-related payables and the corresponding receivable from Hoactzin as of December 31, 2011 in its Consolidated Balance Sheets under "Accounts payable – other" and "Accounts receivable – related party". No Tengasco funds have been advanced by Tengasco to pay any obligations of Hoactzin. No borrowing capability of Tengasco has been used by the Company in connection with its obligations under the Management Agreement. The Management Agreement terminates at the earlier of the date of sale, if any, by Hoactzin of its managed properties, or December 2012.

4. Deferred Conveyance/Prepaid Revenues

The Company has adopted a deferred conveyance/prepaid revenues presentation of the transactions between the Company and Hoactzin Partners, L.P. on September 17, 2007 to more clearly present the effects of the three-part transaction consisting of the Ten Well Program, the Methane Project and a contingent exchange option agreement.

To reflect the deferred conveyance, the Company has allocated $0.9 million of the $3.85 million Purchase Price paid by Hoactzin for its interest in the Ten Well Program to the Methane Project, based on a relative fair value calculation of the Methane Project's portion of the projected payout stream of the combined two projects as seen at the inception of the agreement, utilizing then current prices and anticipated time periods when the Methane Project would come on stream. The Ten Well Program at inception was $2.95 million and the prepaid revenues were $0.9 million.

The Company has established separate deferred conveyance and prepaid revenue accounts for the Ten Well Program and the Methane Project. Release of the deferred amounts to the Ten Well Program will be made as proceeds are actually distributed to Hoactzin. Release will be made on the respective proceeds only as to each project until either one or both satisfy the threshold amount that removes the contingent equity exchange option. The prepaid revenues will be released using the units of production method.

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5. Oil and Gas Properties

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

	December 31,	
	2011	2010
Oil and gas properties, at cost	$ 36,002	$ 27,837
Unevaluated properties	268	189
Accumulated depreciation, depletion and amortization	(16,064)	(13,869)
Oil and gas properties, net	$ 20,206	$ 14,157

During the years ended December 31, 2011, 2010, and 2009, the Company recorded depletion expense of $2.2 million, $1.9 million and $1.8 million, respectively.

6. Other Property and Equipment

Other property and equipment consisted of the following: (in thousands)

December 31,	Depreciable Life	2011	2010
Machinery and equipment	5-7 yrs	$ 969	$ 955
Vehicles	2-5 yrs	789	559
Other	5 yrs	64	64
Total		1,822	1,578
Less accumulated depreciation		(1,396)	(1,270)
Other property and equipment-net		$ 426	$ 308

The Company uses the straight-line method of depreciation for other property and equipment. The Company recorded depreciation expense of $0.2 million in each of the years 2011, 2010, and 2009.

7. Long-Term Debt

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

December 31,	2011	2010
Note payable to a financial institution, with interest only payment until maturity.	$11,531	$9,501
Installment notes bearing interest at the rate of 5.5% to 8.25% per annum collateralized by vehicles with monthly payments including interest, insurance and maintenance of approximately $20,000	266	192
Total long-term debt	11,797	9,693
Less current maturities	(103)	(129)
Long-term debt, less current maturities	$11,694	$9,564

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At December 31, 2011, the Company had a revolving credit facility with F&M Bank & Trust Company (“F&M Bank”).

Under the credit facility, loans and letters of credit are available to the Company on a revolving basis in an amount outstanding not to exceed the lesser of $40 million or the Company’s borrowing base in effect from time to time. The credit facility is secured by substantially all of the Company’s producing and non-producing oil and gas properties and pipeline and the Company’s Methane Project assets. The credit facility includes certain covenants in which the Company is required to comply. These covenants include leverage, interest coverage, minimum liquidity, and general and administrative coverage ratios. During 2011 and 2010 the Company was in compliance with all covenants.

On July 30, 2010, the Company and F&M Bank entered into an amendment to the credit facility which increased the borrowing base from $11 million to $14 million, set the interest rate to the greater of prime plus 0.25% or 5.25% per annum (rate at December 31, 2011 was 5.25%), eliminated the monthly commitment reduction, and changed the maturity date to January 27, 2012.

On February 22, 2011, the Company and F&M Bank entered into an amendment to the credit facility which increased the borrowing base from $14 million to $20 million, increased the maximum line of the Company’s credit amount from $20 million to $40, million, and extended the term of the facility to January 27, 2013.

On July 14, 2011 F&M Bank reaffirmed the Company’s borrowing base at $20 million.

The total borrowing by the Company under the facility at December 31, 2011 and December 31, 2010 was $ 11.5 million and $9.5 million, respectively. The next borrowing base review will take place in June 2012.

8. Commitments and Contingencies

The Company is a party to lawsuits in the ordinary course of its business. The Company does not believe that it is probable that the outcome of any individual action will have a material adverse effect, or that it is likely that adverse outcomes of individually insignificant actions will be significant enough, in number or magnitude, to have in the aggregate a material adverse effect on its financial statements. On March 1, 2010, the Company entered into a lease for office space in Knoxville, Tennessee. The term of the lease is 41 months (five of which are free) and expires on July 31, 2013. The payment on this lease was $7,284 per month through December 2011 and $7,294 per month for the remainder of the lease.

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Future non-cancellable commitments related to this lease are as follows (in thousands):

Year	
2012	$ 80
2013	51
	$ 131

Office rent expense for each of the three years ended December 31, 2011, 2010, and 2009 was $0.1 million.

9. Fair Value Measurements

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

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

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

Level 3 – Unobservable inputs that are supported by little or no market activity, generally requiring a significant amount of judgment by management.

The assets or liabilities fair value measurement level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. Valuation techniques used need to maximize the use of observable inputs and minimize the use of unobservable inputs. Following is a description of the valuation methodologies used for assets measured at fair value.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. Furthermore, although the Company believes its valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of

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certain financial instruments could result in a different fair value measurement at the reporting date.
The following table sets forth by level, within the fair value hierarchy, the Company's liabilities at fair value as of December 31, 2011 and 2010. During 2011 and 2010, there were no changes in the fair value level classification. (in thousands)

December 31, 2011	Level 1	Level 2	Level 3
Derivative assets	$-	$142	$-
Total liabilities at fair value	$-	$142	$-

December 31, 2010	Level 1	Level 2	Level 3
Derivative liabilities	$-	$687	$-
Total liabilities at fair value	$-	$687	$-

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

10. Derivatives

On July 28, 2009, the Company entered into a two-year agreement on crude oil pricing. This "costless collar" agreement was effective August 1, 2009 through July 31, 2011 and had a $60.00 per barrel floor and $81.50 per barrel cap on a volume of 9,500 barrels per month during the period from August 1, 2009 through December 31, 2010, and 7,375 barrels per month from January 1, 2011 through July 31, 2011. The prices referenced in this agreement were WTI NYMEX. While the agreement was based on WTI NYMEX prices, the Company receives a price based on Kansas Common plus bonus, which results in a price approximately $7 per barrel less than current WTI NYMEX prices. As of August 1 2011, the "costless collar" agreement had expired.
On June 27, 2011 the Company entered into an agreement with Cargill, Incorporated for the period from August 1, 2011 through December 31, 2012 ("Cargill Agreement"). The agreement provides to the Company a $65 per barrel floor on a stated quantity of 10,000 barrels per month, which is approximately half of the Company's current production of oil. If the average price falls below $65 per barrel, then Cargill will pay to the Company the difference between $65 and the lower average price for 10,000 barrels per month in each month during when such lower average prices occur. However, unlike the "costless collar" arrangement, the Company will not have a price cap on any portion of its production volumes. The cost to the Company was $2.20 per barrel per month or a total of $374,000 for the entire period of the agreement. This cost was paid by the Company on June 27, 2011.

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These agreements were primarily intended to help maintain and stabilize cash flow from operations if lower oil prices return.

As of December 31, 2011, the Company's open forward positions were as follows (fair value is based on methodology described in footnote 9 Fair Value Measurement):

Period	Monthly Volume	Total Volume	Floor/Cap NYMEX	Fair Value at December 31, 2011
	Oil (Bbls)	Oil (Bbls)	$ per Bbl	(in thousands)
1st Qtr 2012	10,000	30,000	$65.00-N/A	$ 2
2nd Qtr 2012	10,000	30,000	$65.00-N/A	$ 23
3rd Qtr 2012	10,000	30,000	$65.00-N/A	$ 48
4th Qtr 2012	10,000	30,000	$65.00-N/A	$ 69
			Current Asset	$ 142

The Company records changes in the unrealized derivative asset or liability as a "Gain (loss) on derivatives" in the Consolidated Statements of Operations. The Company recorded a $0.45 million unrealized gain during 2011 and a $0.63 million unrealized gain during 2010.

During 2011, the Company made settlement payments related to the "costless collar" of $0.86 million. These realized losses were recorded as a "Gain (loss) on derivatives" in the Consolidated Statements of Operation. During 2010, the Company made settlement payments of $0.13 million.

11. Asset Retirement Obligation

Our asset retirement obligations represent the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives in accordance with applicable laws. The following table summarizes the Company's Asset Retirement Obligation transactions for the years ended December 31, 2010 and 2011: (in thousands):

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Balance December 31, 2009	$ 450
Accretion expense	112
Liabilities incurred	11
Liabilities settled	(75)
Revision in estimated liabilities	939
Balance December 31, 2010	$ 1,437
Accretion expense	96
Liabilities incurred	57
Liabilities settled	(165)
Revisions in estimated liabilities	502
Balance December 31, 2011	$1,927

The revisions in estimated liabilities resulted primarily from increasing estimated plugging cost on Kansas and Tennessee wells based on the actual cost incurred on the wells plugged in 2010 and 2011.

12. Stock Options

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

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Stock option activity in 2011, 2010, and 2009 is summarized below:

	2011		2010		2009	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding, beginning of year	1,571,000	$0.60	3,021,000	$0.42	2,931,000	$0.38
Granted	186,745	$1.01	396,000	$0.44	500,000	$0.54
Exercised	(50,000)	$0.57	(1,831,000)	$0.27	(410,000)	$0.27
Expired/cancelled	(236,745)	$0.82	(15,000)	$0.58	-	-
Outstanding end of year	1,471,000	$0.61	1,571,000	$0.60	3,021,000	$0.42

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

Weighted Average Exercise Price	Options Outstanding (shares)	Weighted Average Remaining Contractual Life (years)	Options Exercisable (shares)
$0.57	400,000	1.1	400,000
$1.44	75,000	1.4	75,000
$0.70	75,000	2.0	75,000
$0.50	400,000	3.8	160,000
$0.43	75,000	3.1	75,000
$0.44	296,000	3.7	296,000
$1.08	75,000	4.3	75,000
$1.16	25,000	4.3	25,000
$0.84	25,000	4.5	25,000
$0.72	25,000	4.8	25,000
	1,471,000		1,231,000

During 2011, the Company issued the following options to each of the non-executive directors that remain outstanding as of December 31, 2011. These options vested upon grant date.

Options Issued to Each Non-executive Director	Total Options Issued to Non-executive Directors	Exercise Price	Grant Date	Expiration Date
25,000	75,000	$ 1.08	3/17/2011	3/16/2016
6,250	25,000	$ 1.16	4/1/2011	3/31/2016
6,250	25,000	$ 0.84	7/6/2011	7/5/2016
6,250	25,000	$ 0.72	10/3/2011	10/2/2016

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The weighted average fair value per share of options granted in 2011 was $0.55 and 2010 was $0.24 calculated using the Black Scholes option pricing model.

Compensation expense related to stock options was $0.2 million in 2011 and was $ 0.1 million in 2010 and $0.2 million in 2009. At December 31, 2011, there was $0.06 million of total unrecognized compensation costs related to unvested options that is expected to be recognized over a weighted average period of approximately 1.75 years.

The fair value of stock options used to compute share based compensation is the estimated present value at grant date using the Black Scholes option pricing model with weighted average assumptions for 2011 of expected volatility of 59.3%, a risk free interest rate of 3.64% and an expected option life remaining from 1.1 to 4.8 years. The weighted average assumptions for 2010 were expected volatility of 62.4%, a risk free interest rate of 3.77% and an expected option life remaining from 2.1 to 4.7 years. The weighted average assumptions used for 2009 were expected volatility of 100%, a risk fee interest rate of 3.67% and an expected option life remaining for 0.3 years to 5.7 years.

13. Income Taxes

The Company had taxable income for the years ended December 31, 2011 and 2010, but had no taxable income for the year ended December 31, 2009.

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

	2011	2010	2009
Statutory rate	34%	34%	34%
Tax (benefit) / expense at statutory rate	$ 1,647	$ (964)	$ (744)
State income tax (benefit) expense	214	(125)	(97)
Permanent difference	34	-	-
Other	8	-	-
Net Change in deferred tax asset valuation allowance	(1,741)	-	672
Total income tax provision (benefit)	$ 162	$ (1,089)	$ (169)

Management has evaluated the positions taken in connection with the tax provisions and tax compliance for the years included in these financial statements as required by ASC 740. The Company does not believe that any of its positions it has taken will not prevail on a more likely than not basis. As such no disclosure of such positions was deemed necessary. Management continuously estimates its ability to recognize a deferred tax asset related to prior period net operating loss carry forwards based on its anticipation of the likely timing and adequacy of future net income. As of December 31, 2011, the Company had available approximately $16.2 million of net operating loss carryforwards to offset future taxable income.

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

During the year ended December 31, 2010, Management, using the “more likely than not” criteria for recognition, elected to recognize a deferred tax asset of $1.1 million. The recognition of the deferred tax asset in 2010 relates to net operating loss carryforwards, impairment of pipeline in 2010, and will provide a better matching of income tax expense with taxable income in future periods.

At December 31, 2011 and 2010, the deferred tax asset balance was $10.2 million and $10.4 million, respectively.

As of December 31, 2011, the Company had net operating loss carry forwards of approximately $16.2 million which will expire between 2021 and 2029 if not utilized. Our open tax years include all returns filed for 2008 and later.

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

	Year Ended December 31,	
	2011	2010
Net deferred tax assets (liabilities) - current:		
Unrealized derivative loss - current	$ 164	$ 264
Total deferred tax assets (liabilities) – current	$ 164	$ 264
Net deferred tax assets (liabilities) – noncurrent:		
Net operating loss carryforwards	$ 6,233	$ 7,040
Oil and gas properties	3,341	4,165
Property, Plant and Equipment	430	631
Asset retirement obligation	37	-
Tax credits	36	-
Valuation allowance	-	(1,741)
Total deferred tax assets (liabilities) – noncurrent	$ 10,077	$ 10,095
Net deferred tax asset (liability)	$ 10,241	$ 10,359

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14. Quarterly Data and Share Information (unaudited)

The following tables sets forth for the fiscal periods indicated, selected consolidated financial data

(In thousands, except per share data)

Fiscal Year Ended 2011	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr
Revenues	$ 3,662	$ 4,785	$ 4,357	$4,281
Net income (loss)	354	977	1,186	2,163
Net income (loss) attributable to common shareholders	354	977	1,186	2,163
Income (loss) per common share	$ 0.01	$ 0.02	$ 0.02	$ 0.04

Fiscal Year Ended 2010	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr
Revenues	$ 2,851	$ 3,291	$ 3,286	$ 3,788
Net income (loss)	268	736	188	(2,937)
Net income (loss) attributable to common shareholders	268	736	188	(2,937)
Income (loss) per common share	$ 0.00	$ 0.01	$ 0.00	$ (0.05)

15. Supplemental Oil and Gas Information (unaudited)

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

Capitalized Costs Related to Oil and Gas Producing Activities

The table below reflects our capitalized costs related to our oil and gas producing activities at December 31, 2011 and 2010 (in thousands):

	Years Ended December 31,	
	2011	2010
Proved oil and gas properties	$ 36,002	$ 27,837
Unproved properties	268	189
Total proved and unproved oil and gas properties	$ 36,270	$ 28,026
Less accumulate depreciation, depletion and amortization	(16,064)	(13,869)
Net oil and gas properties	$ 20,206	$ 14,157

Oil and Gas Related Costs

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

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	Years Ended December 31,		
	2011	2010	2009
Property acquisitions proved	$ -	$ -	$ -
Property acquisitions unproved	-	-	-
Exploration cost	708	80	-
Development cost	7,607	3,453	1,020
Total	$ 8,315	$ 3,533	$ 1,020

Results of Operations from Oil and Gas Producing Activities

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

	Year Ended December 31,		
	2011	2010	2009
Revenues	$ 16,862	$ 12,876	$ 9,711
Production costs and taxes	(5,310)	(5,308)	(5,225)
Depreciation, depletion and amortization	(2,195)	(1,938)	(1,800)
Income from oil and gas producing activities	$ 9,357	$ 5,630	$ 2,686

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

Estimated Quantities of Oil and Gas Reserves

The following table sets forth the Company's net proved oil and gas reserves and the changes in net proved oil and gas reserves for the years ended December 31, 2011, 2010 and 2009.

	Oil (MBbls)	Gas (MMcf)	MBOE
Proved reserves at December 31, 2008	1,248	910	1,399
Revisions of previous estimates (1)	1,203	(721)	1,084
Improved recovery	-	-	-
Purchase of reserves in place	-	-	-
Extensions and discoveries	-	-	-
Production	(171)	(73)	(183)
Sales of reserves in place	(7)	--	(7)
Proved reserves at December 31, 2009	2,273	116	2,293
Revisions of previous estimates	360	(64)	350
Improved recovery			

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Purchase of reserves in place			
Extensions and discoveries	37		35
Production	(174)	(25)	(178)
Sales of reserves in place			
Proved reserves at December 31, 2010	2,496	27	2,500
Revisions of previous estimates	10	3	11
Improved recovery	-	-	-
Purchase of reserves in place	-	-	-
Extensions and discoveries	274	-	274
Production	(189)	(26)	(193)
Sales of reserves in place	-	-	-
Proved reserves at December 31, 2011	2,591	4	2,592
Proved developed reserves at:			
December 31, 2009	1,579	116	1,598
December 31, 2010	1,800	27	1,804
December 31, 2011	1,939	4	1,940
Proved undeveloped reserves at:			
December 31, 2009	694	-	694
December 31, 2010	696	-	696
December 31, 2011	652	-	652

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

	Year Ended 12/31/11			Year Ended 12/31/10			Year Ended 12/31/09		
	Oil	Gas	Total	Oil	Gas	Total	Oil	Gas	Total
Total proved reserves year-end reserve report	$69,748	$15	$69,763	$48,331	$13	$48,344	$27,964	$223	$28,187
Proved developed producing reserves (PDP)	$46,606	$15	$46,621	$28,974	$13	$28,987	$15,476	$223	$15,699
% of PDP reserves to total proved reserves	67%	-	67%	60%	-	60%	55%	1%	56%
Proved developed non-producing reserves	$3,977	-	$3,977	$7,476	-	$7,476	$5,185	-	$5,185
% of PDNP reserves to total proved reserves	6%	-	6%	15%	-	15%	18%	-	18%

Proved undeveloped reserves (PUD)	$19,165	-	$19,165	$11,881	-	$11,881	$7,303	-	$7,303
% of PUD reserves to total proved reserves	27%	-	27%	25%	-	25%	26%	-	26%

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Standardized Measure of Discounted Future Net Cash Flows

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

	December 31,		
	2011	2010	2009
Future cash inflows	$ 229,366	$ 180,569	$ 122,844
Future production costs and taxes	(82,086)	(70,771)	(56,550)
Future development costs	(12,611)	(13,283)	(11,039)
Future income tax expenses	(34,750)	-	-
Future net cash flows flows	99,919	96,515	55,255
Discount at 10% for timing of cash flows	(48,010)	(48,171)	(27,068)
Standardized measure of discounted future net cash flows	$ 51,909	$ 48,344	$ 28,187

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

	December 31,		
	2011	2010	2009
Balance, beginning of year	$ 48,344	$ 28,187	$10,293
Sales, net of production costs and taxes	(11,552)	(7,568)	(4,486)
Discoveries and extensions, net of costs	10,923	2,099	-
Purchase of reserves in place	-	-	-
Sale of reserves in place	-	-	(109)
Net changes in prices and production costs	15,428	15,554	10,433
Revisions of quantity estimates	343	8,873	17,705
Previously estimated development cost incurred during the year	5,346	3,806	28
Changes in future development costs	(1,109)	(3,168)	(5,489)
Changes in production rates and other	(2,336)	(2,037)	(1,217)
Accretion of discount	4,376	2,598	1,029
Net change in income taxes	(17,854)	-	-
Balance, end of year	$ 51,909	$ 48,344	$28,187

Estimated future net cash flows represent an estimate of future net revenues from the production of proved reserves using average sales prices, along with estimates of the operating costs, production taxes and future development and abandonment cost (less salvage value) necessary to produce such reserves. Future income taxes were calculated by applying the statutory federal and state income tax rates to pre-tax future net cash flows, net of the tax basis of the properties and utilizing available tax loss carryforwards related to oil and gas operations. The prices used for December 31, 2011,2010, and 2009, were $88.53, $72.30, $53.81 per barrel of oil and $4.16, $4.89, $4.61, per MCF of gas, respectively. The Company's proved reserves as of December 31, 2011, 2010 and 2009 were measured by using commodity prices based on the twelve month unweighted arithmetic average of the first day of the month price for the period January through December. The Company's proved reserves as of December 31, 2008 were measured by using end of year prices. No deduction has been made for depreciation, depletion or any indirect costs such as general corporate overhead or interest expense.

16. Subsequent Events

On January 3, 2012, the Company issued options to purchase 25,000 common shares at $0.75 per share to the non-executive directors. These options vested upon grant date and will expire on January 2, 2017.
On March 14, 2012 the Company and F&M Bank entered into an amendment to the credit facility which increased the borrowing base from $20 million to $23 million and changed the maturity date to January 27, 2014.