TENGASCO INC
Form 10-K
March 16, 2009

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, 2008** 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)

Tennessee (State or other jurisdiction of incorporation or organization)	**87-0267438** (I.R.S. Employer Identification No.)

10215 Technology Drive N.W., Knoxville, Tennessee 37932-3379

(Address of Principal Executive Offices) (Zip Code)

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

Securities registered pursuant to Section 12(b) of the Act: **None.**
Securities registered pursuant to Section 12(g) of the Act: **Common Stock, $.001 par value per share.**

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

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

Indicate 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 o

Indicate by check mark if disclosure of delinquent filers in response to Item 405 of Regulation SK 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 o	Accelerated Filer [X]	Non-accelerated Filer o (Do not check if a Smaller Reporting Company)	Smaller Reporting Company o

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

State 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 (June 30, 2008 closing price $2.67): **$100,170,369**

State the number of shares outstanding of the registrant's $.001 par value common stock as of the close of business on the latest practicable date (March 2, 2009): **59,350,661**

Documents Incorporated By Reference

The information required by Part III of the 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 June 2, 2009, 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" regarding the future. Forward-looking statements a include statements regarding revenue, margins, expenses, and earnings analysis for 2008 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 statements. 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 the past year 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.

PART I

ITEM 1. BUSINESS.

History of the Company

The Company was initially organized in Utah in 1916 for the purpose of mining, reducing and smelting mineral ores, under the name Gold Deposit Mining & Milling Company and 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.

Overview

The Company is in the business of exploring for and producing oil and natural gas in Kansas and Tennessee.

The Company leases producing and non-producing properties with a view toward exploration and development and owns pipeline and other infrastructure facilities used to provide transportation services. The Company utilizes seismic technology to improve the discovery of reserves.

The Company's primary area of production and development is in Kansas. The Company's activities in Kansas commenced in 1998 when it acquired approximately 32,000 acres of leases and production in the vicinity of Hays, Kansas (the "Kansas Properties"). During 2008, the Kansas Properties produced an average of 19,623 barrels of oil per month.

The Company's oil and gas leases in Tennessee are located in Hancock, Claiborne, and Jackson counties. The Company has drilled primarily on a portion of its leases known as the Swan Creek Field in Hancock County focused within what is known as the Knox Formation, one of the geologic formations in that field. During 2008, the Company sold an average of 215 thousand cubic feet of natural gas per day and 533 barrels of oil per month from 19 producing gas wells and 4 producing oil wells in the Swan Creek Field.

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, is engaged in developing and operating treatment and delivery facilities using the latest developments in available technologies for the extraction of methane gas from non-conventional sources for delivery through the nation's existing natural gas pipeline system, including the Company's TPC 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. As consideration for that agreement the Company obtained reimbursement from Hoactzin of a portion of salary and expenses for the Company's Vice President Patrick McInturff, as well as an option to participate in production and exploration activities in Hoactzin's properties in those areas. 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 Company's Kansas Properties presently include 184 producing oil wells in the vicinity of Hays, Kansas. The Company employs a full time geologist in Kansas to oversee acquisition of new properties, and exploration and exploitation of Kansas Drilling prospects on both newly acquired acreage and existing leases for development. The Company employs a full

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time production manager to oversee the daily function of all producing wells and to implement the work-over programs employed by the Company to boost production from older wells.

On July 2, 2008, the Company acquired 19 leases encompassing approximately 1,577 acres and 41 producing wells producing approximately 80 barrels of oil per day in Rooks County, Kansas together with salt water disposal wells and related equipment from Black Diamond Oil, Inc. for $5.35 million. The leases acquired are in the Company's core area in Kansas and comprise what is known as the Riffe Field that had been owned and operated by Black Diamond for many years. The Riffe Field production that was purchased has yielded immediate benefits to the Company's oil production. The Company has completed several polymer treatments on existing Riffe Field wells that has resulted in increasing production by the end of December 2008 to 147 barrels of oil per day. Total production from the acquired wells during the six month period the Company owned them in 2008 was 21,995 barrels of oil, an average of 122 barrels per day.

In addition to the Riffe Field acquisition, in 2008, the Company continued to focus its exploration and drilling activities in Kansas. In 2008, the Company drilled twelve gross new wells on its Kansas Properties, one of which was the last well drilled in the Company's ten-well program discussed below in greater detail. Of these new wells, nine are producing commercial quantities of oil, including a wildcat well, the Albers #1 in Trego County, Kansas. These new wells are producing approximately 84 barrels of oil per day. The Company also continued in 2008 its program of work-overs of existing wells to increase production. The Company's continued focus on its Kansas oil production and the results achieved by the Company from the Riffe Field acquisition and the Company's ongoing operations, drilling and work-overs have had a positive impact on increasing the Company's oil production.

The Riffe Field acquisition also continued in 2008 the Company's lease acquisition program in Kansas to acquire oil and gas leases in areas near its previous lease holdings where the Company believes there is a likelihood of additional oil production. The Company continued to collect and analyze substantial seismic data to aid it in its drilling operations. While the Company intends in 2009 to continue to acquire strategic leases in the area of its existing wells, the decline in oil prices may have an adverse impact on those plans. Any prolonged decrease in oil prices will have a chilling effect on the Company's plans and abilities to acquire new leases since the acquisition of such properties may not be commercially reasonable at lower oil prices.

A. Kansas Drilling Programs

1. The Ten Well Program

On September 17, 2007, the Company entered into a drilling program with Hoactzin for ten wells consisting of approximately 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 was to pay the Company $400,000 for each well in the Program completed as a producing well and $250,000 per drilled well that was non-productive.

The terms of the 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% of working interest revenues when net revenues received by Hoactzin reach an agreed payout point of approximately 1.35 times Hoactzin's purchase price (the "Payout Point").

In March 2008, the Company drilled and completed the tenth and final well in the Program as a producing well. Of the ten wells drilled, nine were completed as oil producers and are currently producing approximately 106 barrels per day in total. Hoactzin paid a total of $3,850,000 (the "Purchase Price") for its interest in the Program resulting in the Payout Point being determined as $5,215,595. The Purchase Price paid by Hoactzin for its interest in the Program wells exceeded the Company's actual drilling costs of approximately $2.6 million for the ten wells by more than $1 million.

In 2008, the wells from the Program produced 35,827 barrels of oil of which 21,500 were net to Hoactzin. As of December 31, 2008, net revenues received by Hoactzin from the Program total $1,899,835 which leaves a balance of $3,315,759 until the Payout Point is reached.

Although production level of the Program wells will decline with time in accordance with expected decline curves for these types of well, based on the drilling results of the Program wells and the current price of oil, the Program wells are expected to reach the Payout Point in approximately four years solely from the oil revenues from the wells. However, under the terms of its agreement with Hoactzin reaching the Payout Point could be accelerated by the application of 75% of the net proceeds Hoactzin receives from the methane extraction project being developed by the Company's wholly-owned subsidiary, Manufactured Methane Corporation, at the Carter Valley, Tennessee landfill (the "Methane Project") toward reaching the Payout Point. (The Methane Project is discussed in greater detail below.) The Methane Project proceeds when applied will result in the Payout Point being achieved sooner than the estimated four year period based solely upon revenues from the Program wells.

On September 17, 2007, the Company entered into an additional agreement with Hoactzin providing that if the Ten Well 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 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 with a liquidation value equal to 20% of the Purchase Price less the net proceeds received at the time of any exchange. The conversion option would be set at issuance of the preferred stock at the then twenty business day trailing average closing price of Company stock on the American Stock Exchange. This option can not occur at year-end 2009 because approximately 50% of the Purchase Price was returned to Hoactzin from revenues from the wells in the Program by the end of 2008.

Hoactzin has a similar option each year after 2010 in which Hoactzin's then-unrecovered Purchase Price at the beginning of the year is not reduced 20% further by the end of that year, using the same conversion option calculation. The Company, however, may in any year make a cash payment from any source in the amount required to prevent such an exchange option for preferred stock from arising. In addition, the conversion right is limited to a conversion of no more than 19% in the aggregate of the outstanding common shares of the Company. In the event Hoactzin's 75% net profits interest in the Methane Project were fully exchanged for preferred stock Hoactzin would retain no net profits interest in the Methane Project after the full exchange.

Under this exchange agreement, if no proceeds at all were received by Hoactzin through 2009 or in a later year (i.e. a worst-case scenario already impossible in view of the success of the Program), then Hoactzin would have an option to exchange 20% of its interest in the Methane Project beginning in 2011 and each year thereafter for preferred stock convertible at the trailing average price before each year's issuance of the preferred. The number of common shares into which the preferred stock could be converted cannot be currently calculated. because the conversion price is based on a future stock price.

However, as stated, as of December 31, 2008, net revenues received by Hoactzin from the wells in the Program in 2008 totaled $1,899,835 leaving a balance of $1,950,195 to the point at which no preferred stock can be issued to Hoactzin under the Program, thus making it highly unlikely that any preferred stock will ever be issued to Hoactzin. The Company notes that with the demonstrated successful results of production from the wells in the Program that the payout of 25% of the Purchase Price was reached by year-end 2008, a full year before the December 31, 2009 date and no requirement to issue preferred stock will arise in 2010. The Company further anticipates that at current prices of about $40 per barrel of oil and $5.00 per MCF of gas, and at currently expected sales levels of methane gas from the Methane Project to come online in 2009, that the balance of the unrecovered Purchase Price by Hoactzin will be fully recovered by Hoactzin by year-end 2010. As a result, the Company believes it is highly unlikely that any obligation to issue preferred stock will arise under the terms of this agreement at any time in the future.

2. The Eight Well Program

An eight-well drilling program in Kansas (the “Eight Well Program”) was offered to the holders of the Company’s Series A 8% Cumulative Convertible Preferred Stock (“Series A Shares”) in 2006 in exchange for their Series A Shares. This resulted in the participants acquiring approximately an 81% working interest in the eight wells and the Company retaining the remaining 19% working interest. Under the terms of the Eight Well Program, the former Series A shareholders participating in the Eight Well Program were to receive all of the cash flow from their 81% working interest in the eight wells until they recovered 80% of the face value of the Series A Shares they exchanged for their interests in the Eight Well Program. At that point, for the rest of the productive lives of those eight wells, the Company will receive 85% of the cash flow from the 81% working interest in those wells as a management fee and the Series A shareholders will receive the remaining 15% of the cash flow.

All of the wells in the Eight Well Program have been drilled and have produced sufficient revenues to the participants so that the management fee to the Company became effective in 2007. This had the effect of increasing the Company’s net interest in the Program Wells from approximately 19% to an effective 88% interest and resulting in approximately an additional $50,000 in revenues per month at 2007 oil prices to the Company’s interest in those wells. In 2008, the Eight Well Program produced 17,510 gross barrels of oil of which 15,321 barrels were net to the Company.

3. The Twelve (Six) Well Program

In 2005, the Company accepted an exchange from Hoactzin of promissory notes made by the Company in the principal amount of $2,514,000 for a 94.3% working interest in a twelve well drilling program (the “Twelve Well Program”) by the Company on its Kansas Properties. The Company retained the remaining 5.7% working interest in the Twelve Well Program. The promissory notes exchanged were originally issued by the Company in connection with loans made to the Company by Dolphin Offshore Partners, L.P. to fund the Company’s cash exchange to holders of its Series A, B and C Preferred Stock.

The Company drilled six of the wells in the Twelve Well Program. All but one of those wells is continuing to produce commercial quantities of oil. On June 29, 2006 the Company borrowed $2,600,000 pursuant to its credit facility with Citibank Texas, N.A. and used $1.393 million of the loan proceeds to exercise its option to repurchase from Hoactzin, its obligation to drill the final six wells in the Company’s Twelve Well Program. As a result of the repurchase, the Twelve Well Program was converted to a six well program, all of which had been drilled by the Company at the time of the repurchase. If the Company had not exercised its repurchase option, Hoactzin would have received a 94% working interest in the final six wells of the Twelve Well Program. However, as a result of the repurchase, Hoactzin receives only a 6.25% overriding royalty in six Company wells to be drilled, plus an additional 6.25% overriding royalty in the six program wells that had previously been drilled as part of the Twelve Well Program. These overriding royalties were part of the terms agreed upon at the inception of the Twelve Well Program if the repurchase option were exercised.

In 2008, the six wells of the converted Twelve Well Program produced 8,963 barrels of oil of which 6,013 barrels were net to the Company.

The Company has completed all of its drilling obligations under the Eight Well and Twelve Well Programs the Company entered into to facilitate the buy-out of its Series A, B and C former preferred stockholders. In addition, revenues from these Program Wells have been sufficient so that in April 2008, the Twelve Well Program joined the Eight Well Program in reaching the reversionary “payout point” at which the Company starts to receive a management fee equal to 85% of the cash flow from the participants' working interest from the six wells in the Twelve Well Program. That management fee together with the Company's original working interest results in increasing the Company's net effective working interest in the wells of both the Eight and Twelve Well Programs from 19% to 88%.

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B. Kansas Production

The Company's gross oil production in Kansas increased in 2008 from 2007 by 30%. In 2008, the Company produced 231,598 barrels of oil in Kansas compared to 178,311 in 2007. In 2008, the wells in the Eight Well Program produced 17,513 gross barrels of oil; the wells in the Twelve Well Program (now converted to a six well program) produced 8,963 gross barrels; the wells in the Ten Well Program produced 35,827 gross barrels of oil; wells that were polymered produced 14,309 barrels; and the nine new wells drilled in 2008 in which the Company had a 100% working interest produced 23,051 barrels of oil of which, after landowner's royalties, 20,170 barrels were net to the Company.

There are also additional capital development projects that the Company is considering to increase current oil production with respect to the Kansas Properties, including recompletion of wells and major work-overs. Previously this development was funded by cash flow from the Company's operations, which have been negatively impacted by current lower oil prices. These current lower oil prices means that cash flow development will slow dramatically in 2009 from the development levels in 2008. At this time, drilling plans and development of proved undeveloped ("PUD") wells have been pushed back to the end of 2009 or beyond, depending on future oil prices and the economics of that development. These former PUD wells are not included in the Company's December 31, 2008 reserve report (see, Item 2, "Properties – Reserve Analysis" of this Report) and the corresponding volumes from those PUD wells also have been removed due to the price effect of the end of the year oil pricing.

2. The Tennessee Properties

In the early 1980's Amoco Production Company owned approximately 50,500 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. These wells, once completed, had a high pressure and apparent volume of deliverability of natural gas. 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 across three mountain ranges and crossing the environmentally protected Clinch River from Sneedville, Tennessee to deliver gas from the Swan Creek Field to the closest market in Rogersville, Tennessee. 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 which is owned and operated by Tengasco Pipeline Corporation ("TGC"), the Company's wholly-owned subsidiary, extends 65 miles from the Swan Creek Field to a meter station at Eastman Chemical Company's ("Eastman") plant in Kingsport, Tennessee.

Eastman is the primary customer of the gas produced from the Company's Swan Creek Field. The pipeline system was built for a total cost of $16,329,552.

B. Swan Creek Production and Development

The Company has concluded based on the results of drilling and testing two infield development wells in 2004 together with the accumulation of data from 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; the current wells in production in the Swan Creek Field would be capable of and would likely produce all the remaining reserves in that Field; and, that only limited additional gas reserves could be added with additional infield developmental drilling. As a result, the Company has not drilled any new gas wells in the Swan Creek Field in over four years.

Because no drilling for natural gas directly in Swan Creek is anticipated in the future, the current production levels less decline are the sole value of natural gas reserves and production. The existing production and the current 19 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 from 2007 to 2008 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 the decline experienced over the 2007-2008 period, and that ongoing production from existing wells will tend to stabilize near current production levels. Variations in year-end natural gas prices and lack of interest to invest in Swan Creek in the foreseeable future have resulted in an adjustment to the reserve volumes to reflect only the reserves associated with currently producing wells. The Company maintains an interest and anticipates drilling additional oil prospects in Swan Creek. It also has an interest in seeking other exploration targets in Tennessee outside of Swan Creek but near the Company's pipeline, with other industry partners.

The deliverability of natural gas from the Swan Creek Field will not be sufficient to satisfy the volumes deliverable under its contracts with Eastman and BAE in Kingsport, Tennessee. The Eastman contract provides that Eastman will buy a minimum of the lesser of eighty percent of that customer's daily usage or 10,000 MMBtu per day, and the BAE contract provides that BAE will buy a minimum of all of that customer's usage or 5,000 MMbtu per day after Eastman's volumes have been provided. In 2008, the Company's volume sold from the field was approximately 215 MMBtu per day. The Company's contracts with these customers are for natural gas produced from the Swan Creek Field. So long as that field is not capable of supplying these volumes of natural gas, the Company is not in breach or violation of these contracts. No penalty is associated with the inability of the Field to produce the volumes that the Company could deliver and buyers would be obligated to buy under their industrial contracts if the volumes were physically available from the Field. However, in the event that the Company was found to be in breach of its obligations for failure to deliver any volumes of gas that is produced from the Swan Creek Field to either of these customers, the agreements limit potential exposure to damages.

Damages are limited to no more than $.40 per MMBtu for any replacement volumes that are proved in a court proceeding as having been obtained to replace volumes required to be furnished but not furnished by the Company.

During 2008, the Company had 19 producing gas wells and 4 producing oil wells in the Swan Creek Field. Gas sales from the Swan Creek Field during 2008 averaged 215 Mcf per day compared to 347 Mcf per day in 2007.

In January 2008, the Company signed a farmout agreement with Jacobs Energy, L.L.C. ("Jacobs Energy") of Glasgow, Kentucky related to development of the Company's 1,405 leased acres in Hancock County, Tennessee and an additional area of approximately 20,000 surrounding acres constituting an area of mutual interest ("AMI") for the purpose of exploring the rim of the Swan Creek anticline for Devonian shale gas production. The agreement is in the form of a "drill to earn" relationship whereby Jacobs Energy must establish commercial production at its sole cost from the first two test wells in order to earn a 50% interest in the two test wells and the right to participate on a fifty-fifty basis in all remaining wells that may be drilled in the AMI. The Company has no obligation for any of the costs of the two test wells. The Company would bear 50% of the costs of any new wells drilled in the future within the AMI. In the event commercial production is not established, Jacobs Energy does not earn any interest in the test wells nor in the AMI and the farmout agreement terminates.

By the end of 2008, Jacobs Energy had re-completed the Ted Hall No. 1 well, which constituted the completion of the first of the two test wells under the farmout agreement. Jacobs Energy plans to drill the required second test well in 2009. Testing of the Ted Hall No. 1 indicates a possible commercial volume of natural gas; however, the preliminary gas analysis of the gas from this well indicates a high nitrogen level exceeding thirty percent which would prevent the gas from being transported by pipeline without treatment for nitrogen removal. The nitrogen content may decrease as the volume of injected nitrogen that was used to fracture the well is recovered in combination with the natural gas testing volumes currently being produced from the well. However, it is also possible that the nitrogen content may not decrease, as some wells producing from the Devonian shale in this general area are subject to having a higher naturally occurring nitrogen content than would be acceptable in the regional pipeline systems, including the Company's pipeline. Consequently, in order to establish commercial production from this type of well, the nitrogen may need to be physically removed after the gas is produced. Typically, this is performed by installing a treatment plant located at or near the well or wells. An accumulation of many wells is typically required to contribute enough gas production to the treatment plant in order to economically amortize the very significant costs involved in nitrogen removal. Thus, these costs may not be justified in the event significant volumes of gas cannot be physically routed to the treatment plant. The Ted Hall No. 1 well is not currently connected to any pipeline pending the completion and results of the second test well.

When Jacobs Energy drills the second test well (which is expected to occur in 2009) both the volume and gas quality will be considered in determining whether the test wells are capable of commercial production. Under the farmout agreement, the Company has the sole option of determining existence of commercial production from the two test wells.

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Depending on the determination of commercial viability, it will be necessary to lay a pipeline extension of about 2.2 miles in order to tie in any production from these wells to the Company's existing 65-mile Swan Creek pipeline. If the Company determines that the wells are non-commercial, Jacobs Energy may choose to complete the pipeline extension at its own cost, and the Company would credit a portion of any future gas sales proceeds from its 50% interest in the wells, if any sales actually occur, toward repayment for the Company's 50% of the pipeline costs. The Company is not otherwise obligated in that case for any costs of the two test wells or the pipeline. In addition, if the pipeline extension is constructed by Jacobs Energy at its own cost, the Company would incur no penalty for having not consented to construction of the pipeline by Jacobs Energy. It is important to note, however, that if Jacobs Energy completes the pipeline at its own cost, the Company's subsidiary, TPC, is not obligated to accept, and cannot accept the gas under its tariffs on file, if the nitrogen content of the gas tendered for pipeline delivery does not change significantly from the levels currently being produced from the first test well. In summary, upon completion of the two test wells, the anticipated future gas prices, the measured gas volumes from the test wells, and the gas quality and any necessary treatment costs will all have a bearing upon the Company's final determination of whether the project may be capable of producing merchantable natural gas in commercial quantities.

3. The 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 Agreement was assigned to the Company's wholly-owned subsidiary, Manufactured Methane Corporation ("MMC"), and provides that MMC will purchase all the naturally produced gas stream presently being collected and flared at the municipal solid waste landfill in Carter Valley serving the metropolitan area of Kingsport, Tennessee that is owned and operated by Republic in Church Hill, Tennessee. Republic's facility is located about two miles from the Company's existing pipeline serving Eastman Chemical Company ("Eastman"). The Company has 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 gas stream by volume. The Company has constructed a small diameter pipeline to deliver the extracted methane gas to the Company's existing pipeline for delivery to Eastman (the "Methane Project").

The total cost for the Methane Project including pipeline construction, was approximately $4.3 million including costs for compression and interstage controls. 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) $825,000 of the funds the Company borrowed from its credit facility with Sovereign Bank.

Commercial deliveries of gas will begin when the equipment is fully tested and emission permits are obtained. Upon commencement of operations, it is anticipated that the methane gas produced by the project facilities will be mixed in the Company's pipeline and delivered and sold to Eastman under the terms of the Company's existing natural gas purchase and sale agreement with Eastman. At current gas production rates and expected extraction efficiencies, when commercial operations of the Project begin, the Company initially estimated it would deliver about 418 MCF per day of additional gas to Eastman, which would substantially increase the current volumes of natural gas being delivered to Eastman by the Company from its Swan Creek field. The gas supply from this project 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, currently estimated by Republic to occur between the years 2022 and 2026.

As part of the Methane Project agreement, the Company has installed a new force-main water drainage line for Republic, the landfill owner, in the same two-mile pipeline trench as the gas pipeline needed for the project, reducing overall costs and avoiding environmental effects to private landowners resulting from multiple installations of pipeline. Republic has paid the additional material costs for including the water line of approximately $700,000. Construction of the gas pipeline needed to connect the facility with the Company's existing natural gas pipeline began in January 2008 and was completed in December 2008. As a certificated utility, the Company's pipeline subsidiary, TPC, required no additional permits for the gas pipeline construction.

At year-end 2008, MMC was finalizing steps necessary to declare the startup of commercial gas production at the Carter Valley landfill in Church Hill, Tennessee. Initial volumes of methane were produced in late December 2008 and have occurred on an intermittent basis since that time as MMC implemented the startup process. During the first two months of 2009, Eastman was reviewing its current air quality permits with regard to MMC's methane production and deliveries were suspended during that review. Eastman has now indicated to MMC in early March 2009 that it is prepared to commence taking delivery of the methane gas from MMC's Carter Valley facility. Accordingly, MMC expects to declare startup of commercial operations no later than the end of March 2009. Thereafter, MMC, Eastman Chemical, and Republic Services intend to schedule a formal grand opening of this facility in the spring of 2009.

Prior to declaring startup of commercial operations, MMC continues to fully integrate the gas supply from the landfill with the operations of the methane extraction equipment to maximize quality and quantity of the gas produced and to enable continuous daily production from the facility. The Company believes that this process is complete as of the date of this Report. To date, MMC has produced approximately 800 thousand cubic feet of methane gas that was extracted from the landfill gas. The produced methane was mixed with the natural gas produced from the Company's Swan Creek field and delivered to Eastman through the new 2.5 mile pipeline built from the landfill to connect with the Company's existing 65-mile natural gas pipeline.

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The methane gas produced to date is of the high quality levels and heating content that MMC expected with the system design. MMC expects to be able to continuously produce and sell about 500 MCF per day, which significantly exceeds the original estimate of about 418 MCF per day that was made at the beginning of this project. This has happened because the landfill has grown during the time the Project has been in planning and construction, and the landfill owner Republic has improved both the quality and volume of gas collected by the gas gathering system in the landfill itself.

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. When the Methane Project comes online, the revenues from the Project received by Hoactzin will 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 a 7.5% net profits interest. The Company believes that the application of revenues from the methane project to reach the Payout Point could accelerate reaching the Payout Point. As stated above, the Purchase Price paid by Hoactzin for its interest in the Program exceeded the Company's anticipated and actual costs of drilling the ten wells in the Program. Those excess funds provided by Hoactzin were used to pay for approximately $1,000,000 of equipment required for the Methane Project, or about 25% of the Project's capital costs. The availability of the funds provided by Hoactzin eliminated the need for the Company to borrow those funds, to have to pay interest to any lending institution making such loans or to dedicate Company revenues or revenues from the Methane Project to pay such debt service. Accordingly, the grant of a 7.5% interest in the Methane Project to Hoactzin was negotiated by the Company as a favorable element to the Company of the overall transaction.

4. <u>Management Agreement with Hoactzin</u>

The Company entered into a Management Agreement with Hoactzin on December 17, 2007. 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 interests 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 has 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 has granted to the Company an option to participate in up to a 15% working interest for a corresponding price of up to 15% of the actual project costs, in any new drilling or work-over activities undertaken on Hoactzin's managed properties during the term of the Management Agreement. During 2008, the Company did not exercise any option to participate in any such operation.

The term of the Management Agreement is the earlier of the period ending with the date Hoactzin sells its interests in its managed properties or 5 years from the date of the Agreement.

5. <u>Other Areas of Development</u>

The Company is continuing to review and analyze potential acquisitions of additional existing oil and gas production in the Mid-Continent (USA) area. The Company is particularly interested 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 prices, etc. Current economic conditions, including the sharp decline in oil prices, will certainly have an adverse impact on the Company's ability to acquire additional properties. 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. These target evaluations were made using available third party seismic data, the Company's own seismic investigations, and drilling results and geophysical logs from the existing wells in the region. 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. However, 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.

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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, local utilities and private industry end-users. The principal markets for the Company’s natural gas are local utilities, private industry end-users, and natural 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, Eastman and BAE in Sullivan County, as well as other industrial customers in the Kingsport area. The Company has acquired all necessary regulatory approvals and necessary property rights for the pipeline system. The Company's pipeline cannot only provide transportation service for gas produced from the Company's wells, but could provide transportation of gas 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. The Company could, although there can be no assurance, sell its products to certain local towns, industries and utility districts.

At present, crude oil produced by the Company in Kansas is sold at or near the wells to the Coffeyville Resources Refining and Marketing, LLC (“Coffeyville Refining”) in Kansas City, Kansas. Coffeyville Refining is solely responsible for transportation to its refinery of the oil it purchases. 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. 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 via pipeline.

Competitive Business Conditions, Competitive Position in the Industryand 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 the 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 are larger with 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 prices 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

The Company is presently dependent upon a small number of customers for the sale of gas from the Swan Creek Field, principally Eastman, and other industrial customers in the Kingsport area with which the Company may enter into gas sales contracts.

At present, crude oil from the Kansas Properties is being purchased at the well and trucked by Coffeyville Refining, which is 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.

Patents, Trademarks, Licenses, Franchises, Concessions,

Royalty Agreements or Labor Contracts, Including Duration

Royalty agreements relating to oil and gas production are standard in the industry. The amount of the Company's royalty payments varies from lease to lease.

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 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 a seven-inch diameter 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 it 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. 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. In addition, at the federal level, the Federal Energy Regulatory Commission regulates interstate transportation of natural gas under the Natural Gas Act. 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 what affect these present and future laws, rules and regulations will have on the Company's current and future operations.

Research and Development

The Company has not expended any material amount in research and development activities during the last two fiscal years. The Company, however, spent substantial amounts in 2006 and 2007 for the acquisition of seismic data relating to the Company's Kansas Properties and for three-dimensional analysis of the acquired seismic data for the purpose of determining drilling targets with the maximum likelihood of being commercial producers of oil when drilled. The Company's success in 2008 was in large part a result of these investments. The information developed also led to creating an inventory of wells to be drilled. However, recent lower oil prices and the fact that the Company has historically drilled with revenues generated primarily from the Company's operations may limit the development of these drilling targets and restrict the Company's drilling program. In addition, volumes from these drilling targets has been excluded from the Company's current reserve report as of December 31, 2008 since their financial value when future revenues are discounted as a standard measure appears commercially unreasonable at $34.00 per barrel of oil, the 2008 year-end price of oil required to be used under SEC regulations.

Number of Total Employees and Number of Full-Time Employees

The Company presently has thirty full time employees and two part-time employees.

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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 or Designation
Jeffrey R. Bailey 2306 West Gallaher Ferry Knoxville, TN 37932	Chief Executive Officer[1]	6/17/02
Charles Patrick McInturff 7500 San Felipe, Suite 400 Houston, TX 77063	Vice-President	12/18/07
Cary V. Sorensen 5517 Crestwood Drive Knoxville, TN 37914	Vice-President; General Counsel; Secretary	7/9/99
Mark A. Ruth 9400 Hickory Knoll Lane	Chief Financial Officer	12/14/98

Knoxville, TN 37931

Business Experience[2]

Charles Patrick McInturff is 56 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 in 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 work-overs and identification and evaluation of drilling and workover candidates. 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 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 work-overs, 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 entered into a two-year employment agreement with the Company pursuant to which he serves as Vice-President of the Company.

Cary V. Sorensen is 60 years old. He is a 1976 graduate of the University of Texas School of Law and has undergraduate and graduate degrees form 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.

Mark A. Ruth is 50 years old. He is a Certified Public Accountant with 27 years accounting experience. He received a B.S. degree in accounting with honors from the University of Tennessee at Knoxville. He has served as a project controls engineer for Bechtel Jacobs Company, LLC; business manager and finance officer for Lockheed Martin Energy Systems; settlement department head and senior accountant for the Federal Deposit Insurance

Corporation; senior financial analyst/internal auditor for Phillips Consumer Electronics Corporation; and, as an auditor for Arthur Andersen and Company. On December 14, 1998 he became the Company's Chief Financial Officer.

Code of Ethics

The Company's Board of Directors has adopted a Code of Ethics that applies to the Company's financial officers and executive 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 Codes of Ethics can be obtained free of charge by writing to: Cary V. Sorensen, Secretary, Tengasco, Inc., 10215 Technology Drive, Suite 301, Knoxville, TN 37932.

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 450 Fifth Street, N.W., 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 Web site 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 such site is http://www.sec.gov.

The Company's website is located at http://www.tengasco.com. Under the "Finance" section of the website, you may access, free of charge, the Company's Annual Report on Form 10-K, 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 necessarily 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.

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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, 2008, the outstanding principal amount of the Company's indebtedness to Sovereign was approximately $9.9 million. This level of indebtedness, coupled with the widely reported domestic and global recession, the associated low levels of energy prices, and the unprecedented 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 our vulnerability to additional adverse changes in economic and industry conditions; (iii) require the Company to dedicate a substantial portion or all of our cash flow from operations and proceeds of any debt or equity issuances or asset sales to pay or provide for our indebtedness; (iv) limit our ability to respond to changes in our businesses and the markets in which we operate; (v) place us at a disadvantage to our competitors that are not as highly leveraged; or (vi) limit our 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 recent disruption in the global financial and credit markets, as well as the recent significant decline 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 and reduce its drilling plans and capital expenditures as necessary. However, external financing in the capital markets is currently not 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 current distressed state of the credit markets and the pricing for oil and natural gas, our ability to enter into future beneficial relationships with third parties for our exploration and production activities may be limited, and as a result, may have an adverse effect on our 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 Sovereign 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 that the recent 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.

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Additionally, the terms of the Company's amended and restated credit facility with Sovereign restricts 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, 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, or be forced to sell some of the Company's assets on an untimely basis or under unfavorable terms, any of which could have a material adverse effect on the Company's operating results and financial condition.

The Company's Borrowing Base under its

Credit Facility may be reduced by Sovereign Bank.

The borrowing base under the Company's revolving credit facility with Sovereign Bank will be determined from time to time by the lender, as specified in the credit facility, consistent with its customary natural gas and crude oil lending practices. Reductions in estimates of the Company's natural gas and crude oil reserves under the parameters established by the lender 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 lenders' inability to agree to an adequate borrowing base or adverse changes in the lenders' practices regarding estimation of reserves. If cash flow from operations or the Company's borrowing base decrease 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 under the Company's Sovereign Bank revolving credit facility 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 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 with Sovereign Bank.

The Company's Credit Facility with Sovereign Bank Is Subject to Variable Rates of Interest, Which Could Negatively Impact the Company.

Borrowings under the Company's credit facility with Sovereign Bank of Dallas, Texas ("Sovereign 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 its net 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, Sovereign 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 2008, 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. During 2008, the price for oil was extremely volatile. In July 2008, the price of oil reached a record high of $147 per barrel and by December 2008 had declined to approximately $35 per barrel. 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 will continue to 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.

Risks 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 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 recent decline in oil prices in 2008 and the volatility of oil prices makes these projections even more difficult.

The Company has a History of Significant Losses.

During the early stages of the development of its oil and gas business the Company has had a history of significant losses from operations, in particular its development of the Swan Creek Field, and has an accumulated deficit of $ 26,476,148 as of December 31, 2008. Although management has substantially reduced its cash operating expenses, these losses have had a material adverse impact on the operations of the Company's business. The Company was profitable in 2006 and 2007. In 2008, the Company's had an operating profit before ceiling test write down of $4,777,179, but due to a non-cash ceiling write-down limitation of $11,608,397, ($7,661,397 net of tax effects) the Company recorded a net income of $169,662. In the event the Company experiences losses in the future it may curtail the Company's development activities or force the Company to sell some of its assets in an untimely fashion or on less than favorable terms.

The Company's Oil and Gas Operations

Involve Substantial Costs and are Subject

to Various Economic Risks.

The Company's oil and gas oil and gas operations are subject to the economic risks typically associated with exploration, development and production activities, including the necessity of significant expenditures to locate and acquire new producing properties and to drill exploratory and developmental wells. In conducting exploration and development activities, the presence of unanticipated pressure or irregularities in formations, miscalculations or 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 and timing 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 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 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. The current decline in oil prices and any prolonged decline of these 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 condition 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 net reserves 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 or 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 December 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 have been revised downward in the past few years 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 because of the Company's determination that additional drilling or development of Swan Creek may not occur in the foreseeable future based on the Company's determination that 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 natural gas (as opposed to oil where reserves have been materially revised upward in the same period), other revisions in gas reserves, or in oil reserves, in the future 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 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%. If net capitalized costs of natural gas and crude oil properties exceed the ceiling limit, the Company must charge the amount of the excess, net of any tax effects, to earnings. This is called a "ceiling limitation write-down." 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 one 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.

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In 2008, the Company did incur a ceiling limitation write-down net of tax effects in the amount of $7.7 million due to the dramatically lower year-end oil prices in 2008 as compared to 2007 and the resulting significant downward adjustment of the Company's estimated proved reserves. The effect of the ceiling write-down resulted in the Company recording net income of $169,662 in 2008 of despite having an operating profit in 2008 of $4,777,179 before the write down. In light of recent declines in oil prices and forecasts that such prices may continue at lower levels we cannot assure you that the Company will not experience similar ceiling limitation write-downs in the future.

Use of the Company's Net Operating Loss Carryforwards may be Limited.

At December 31, 2008, the Company had, subject to the limitations discussed in this risk factor, substantial amounts of net operating loss carryforwards for U.S. federal 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 Statement No. 109. 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 increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher oil and natural gas prices generally stimulate increased demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. 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

<u>Government Regulation of the Oil and Gas Industry</u>.

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. In addition, at the federal level, the Federal Energy Regulatory Commission regulates interstate transportation of natural gas under the Natural Gas Act. Other regulated matters include marketing, pricing, transportation and valuation of royalty payments.

The Company also has Significant Costs

<u>Related to Environmental Matters</u>.

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 costs or delays in receiving appropriate authorizations.

<u>Insurance Does Not Cover All Risks.</u>

Exploration for and production of oil and natural gas and the Company's transportation and other activities can be hazardous, involving unforeseen occurrences such as blowouts, cratering, 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 from Non-conventional Reserves Operations Involve Substantial Costs 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. These risks could result in a 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.

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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. To the extent that their services become unavailable, the Company would be required to retain other qualified personnel. The Company does not know whether it would be able to recruit and hire qualified persons upon acceptable terms. The Company does not maintain "Key Person" insurance 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 pending and/or 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 American Stock Exchange 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., which is the Company's largest shareholder. At December 31, 2008, 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 75,000 shares of common stock. His ownership and voting control over approximately 35.6% 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 2, 2009, the Company had 59,350,661 shares of common stock outstanding of which 21,727,379 shares were held by affiliates and, in addition, options to purchase 2,9310,000 shares of unissued common stock were granted under the Tengasco, Inc. Stock Incentive Plan (of which options to purchase 2,244,000 shares were vested at March 2, 2009).

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 Interests and Adversely Affect Stock Price.

The Company may in the future issue previously authorized and unissued securities, resulting in the dilution of the ownership interests of its current stockholders.

The Company is currently authorized to issue a total of 100,000,000 shares of common stock with such rights as determined by the Board of Directors. Of that amount, approximately 59 million shares have been issued. The potential issuance of the approximately 41 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 American Stock Exchange, 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 4,607 square feet located at 10215 Technology Drive, Suite 301, Knoxville, Tennessee at a rental of $5,279 per month and an office in Hays, Kansas at a rental of $500 per month. The Company has leased office space in Houston, Texas for use by Patrick McInturff, a vice president of the Company, at a rental of $1,000 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, 2008, the Company does not have a production interest in Texas or Louisiana, but it is anticipated that an opportunity to participate in the properties the Company manages on behalf of Hoactzin Partners, L.P. in those states will be available in the future.

Kansas Properties

The Kansas Properties as of December 31, 2008 contained 211 leases totaling 30,251 acres in the vicinity of Hays, Kansas. The increase in the total volume of acreage of the Company's Kansas Properties from 28,934 acres at the end of 2007 is primarily due to the Company's acquisition of 19 producing leases in the Riffe Field, which is discussed in greater detail in Item 1 of this Report. In 2008, the Company continued to focus its drilling, development, and exploration activities in Kansas on evaluation of older producing properties, and those properties it acquired during the past few years. Many of these leases are still in effect because they are being held by 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 2008, the Company drilled 12 gross wells. The Company has a 100% working interest in all but one of the wells drilled, which was the final well drilled in the Ten Well Program discussed above in Item 1 of this Report.

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. Breaking down the Company's assets in Kansas into individual leases produces no apparent stand out leases that appear to be stand-alone principal properties. As a whole, however, 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 demonstrated by the following facts during the year ending December 31, 2008:

- Kansas accounted for 93.6% of the Company's revenue (i.e. $14.6 million of $15.6 million).
-

Kansas accounted for 91% of the Company's total production measured in BOE (Barrel of Oil Equivalent).

- The Company's focus in 2009 will be to continue with offset seismic development, and leasing activity in Kansas. However, such activity will be greatly affected by oil prices. If oil prices remain at current lower levels for prolonged periods this will have an adverse impact on the Company's development of its properties and acquisition of any new properties.

The map below indicates the location of the Company's top ten leases in Kansas as of December 31, 2008.

The following tables indicate the production from the Company’s top ten leases in 2008 as well as the reserve value of these leases as of December 31, 2008. By comparing these tables with the tables below showing the total production from the Kansas Properties in 2008 and the Company’s aggregate reserve value as of December 31, 2008, it is apparent that none of the Company’s Kansas leases are on their own significant properties, but that they must all be viewed as a whole to appreciate their significance to the Company’s operations.

Largest Kansas Leases by Production

	LEASE	2008 Gross Production barrels	Company Net Revenue Interest	Percentage of Total Oil Production
Total Oil Production 2008			**231,598 Barrels**	
1	McElhaney	11,560	0.22	5%
2	Veverka "A"	11,113	0.22	5%
3	Croffoot	11,092	0.861328	5%
4	Croffoot "B"	8,105	0.8203124	4%
5	McElhaney "A"	7,197	0.875	3%
6	Foster	6,889	0.8476562	3%
7	Harrison "A"	6,612	0.875	3%
8	Veverka "B"	6,124	0.875	3%
9	Albers	6,005	0.875	3%
10	Stahl	5,987	0.84375	3%

Largest Kansas Leases by Reserve Value

(All Reserve Values are Stated in $1000's)

(ALL "VALUES" ARE STATED IN STANDARDIZED MEASURE OF FUTURE CASH FLOWS)

Map #	**Value Of Company Proved Reserves** **LEASE** (Number of Producing Wells)	**Proved Producing Value**	**Proved Undeveloped Value**	**Lease Total Value**	**$10,293,240** **Percentage of Total Lease Value to Company Proved Reserves**
1	McElhaney (1)	$1,624.66	0	**$1,624.66**	16%
2	Veverka B (2)	$1,137.19	0	**$1,137.19**	11%
3	Liebenau (5)	$882.64	0	**$882.64**	9%
4	Harrison A (5)	$717.58	0	**$717.58**	7%
5	Veverka A (2)	$788.40	0	**$788.40**	8%
6	McElhaney A (1)	$656.98	0	**$656.98**	6%
7	Albers (1)	$633.95	0	**$633.95**	6%
8	Croffoot (4)	$614.15	0	**$614.15**	6%
9	Stahl (4)	$583.36	0	**$583.36**	6%
10	Albers A (1)	$550.54	0	**$550.54**	5%
	Croffoot B (6)	$534.92	0	**$534.92**	5%
	Foster (2)	$418.36	0	**$418.36**	4%

Tennessee Properties

The Company's Swan Creek leases are on approximately 8,773 acres in Hancock, Claiborne and Jackson Counties in Tennessee.

Working interest owners in oil and gas wells in which the Company has working interests are entitled to market their respective shares of production to purchasers other than purchasers with whom the Company has contracted. Absent such contractual arrangements being made by the working interest owners, the Company is authorized but is not required to provide a market for oil or gas attributable to working interest owners' production. At this time, the Company has not agreed to market gas for any working interest owner to customers other than customers of the Company. The Company does not anticipate that any working interest owner will request to market its own share of production because there is no viable customer or market for the small volumes of gas attributable to those working interests. If the Company were to agree to market gas for working interest owners to customers other than the Company's customers, the Company would have to agree, at that time, to the terms of such marketing arrangements and it is possible that as a result of such arrangements, the Company's revenues from such production may be correspondingly reduced. If the working interest owners make their own arrangements to market their natural gas to other end users along the Company's pipeline, such gas would be transported by TPC at published tariff rates. If the working interest owners do not market their production, either independently or through the Company, then their interest will be treated as not yet produced and will be balanced either when marketing arrangements are made by such working interest owners or when the well ceases to produce in accordance with customary industry practice.

Reserve Analyses

The Company's estimated total net proved reserves of oil and natural gas as of December 31, 2008, and the present values of estimated future net revenues attributable to those reserves as of those dates, are presented in the following table. These estimates were prepared by LaRoche Petroleum Consultants, Ltd. ("LaRoche") of Houston, 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 estimating the reserve quantities that are economically recoverable, end-of-period natural gas and oil prices, held constant, were used. In accordance with SEC regulations, no price or cost escalation or reduction was considered.

	Total Proved Reserves as of December 31, 2008			
	Producing	Non-producing	Undeveloped	Total
Natural gas (MMcf)	907	2.8	0	910
Oil (Bbls)	1,240	7.73	0	1,248
Total proved reserves (BOE)	2,428	8.2	0	2,436
Standardized measure of discounted future net cash flow	$10,134,445	$ 158,795	$ 0	$ 10,293,240

Under current SEC rules, the Company's proved reserves are measured by what can be described as a "snapshot" analysis based on commodity prices of oil and gas on the last day of each calendar year. Thus, the natural gas and oil prices used in Laroche's reserve reports are the period-end prices for natural gas and oil at December 31, 2008. These prices are held constant in accordance with SEC guidelines for the life of the wells included in the reserve reports but are adjusted by lease for energy content, quality, transportation, compression and gathering fees, and regional price differentials. The weighted average oil and natural gas prices after basis adjustments used in our reserve valuation as of December 31, 2008 were $34.04 per barrel and $7.00 per Mcf.

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, 2008. 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.

The "snapshot analysis" method has been recognized as having limitations, and accordingly the SEC adopted new reserve reporting modernization rules on December 31, 2008 that are now effective for the Company's reserve reporting for the year ending December 31, 2009. However, the effect of this snapshot analysis on the Company in 2008 has caused the Company's reserve volumes and values to drop for two reasons. First, there is the magnified effect of single day snapshot pricing on the Company's "proved, developed producing" reserves, referred to as the PDP reserve category. Although 2008 also saw record high oil prices for crude oil, the pricing used under SEC rules for 2008 for reserve reporting purposes is the December 31, 2008 price of $34.04 per barrel which is approximately 20% of prices received for the Company's oil production in mid-2008 and the lowest oil price in recent memory. Consequently, under the snapshot analysis, the lower 2008 end-of-year oil price has effectively caused the total values of our long-lived PDP reserves to be reduced by the discounted cash flow analysis of the future revenues from each of our wells. In 2007, the Company's PDP reserves were 2,275,970 barrels and were valued at $37.8 million using the 2007 year-end snapshot price of $85.41 per barrel discounted to present value at 10%. In 2008, despite the addition of interests in 12 new wells and all of the same 2007 producing properties, the reserve number fell because of the 2008 year-end snapshot price of $34.04 per barrel resulting in the reserves being determined to be 1,240,000 barrels of PDP reserves valued at $10.134 million.

Another drawback to the snapshot analysis method is that oil wells with lower volumes, long lives, and low production decline rates (like most of our older Kansas wells) are subject to falling out of the reserve valuation methodology many years before they are likely to stop actual production if depressed oil prices are used as the basis for calculations. This occurs at a point in time when future expenses of these wells, which are not reduced for operating low volume wells, meet or exceed the depressed snapshot price for the produced oil, which price is not allowed to escalate. From that point in time onward the well is assumed for valuation purposes to be shut-in or abandoned because it is assumed it would be unprofitable to operate. The consequence of this methodology is that for all outlying years where actual production is physically possible at a reasonable price, production volumes from those outlying years are removed from the PDP reserve valuation altogether, and are not discounted to a present value for 2008 reserve valuation purposes.

The snapshot method also provides another challenge to maintaining the values of “proved undeveloped” reserves (“PUD”). In order to include reserves associated with future drilling on PUD locations, it is necessary to demonstrate that a company has the financial ability to actually drill those locations. Said another way, if a location appears to be likely to produce hydrocarbons, it cannot be included in reserves as PUD if a given company has no way to actually pay for drilling the well to obtain production. Using a lower snapshot price of oil, such as the 2008 year-end price, reduces projected cash flow from existing PDP operations to a level where it may become difficult or impossible to demonstrate that the Company has sufficient cash flow to drill these PUD locations and thereby be able to include the value of the reserves likely to be produced from these locations in the PUD category. In addition, future costs anticipated to be required to drill and operate a PUD location are held to a fixed or current level and are not discounted for lower volumes, while the prices received for future production from such a well are held to the snapshot of the lower year-end price. In places such as Kansas, the discounted reserve values, when based on any low snapshot price are made to appear even less capable of being able to recover drilling and operating costs as is necessary to include the wells in the PUD category. In 2007, the Company had 39 PUD locations that contributed to the Company’s reserve valuation in the amount of $15 million. During 2008, the Company added additional PUD locations to the reserves, and drilled some wells previously on the PUD list from 2007, moving these reserves into the PDP category. Also during 2008, the Company continued to build its PUD elements of value throughout the course of the year from the geologic and engineering points of view. Nevertheless, because of the much lower 2008 year-end price as compared to the 2007 year-end price, the Company was required to remove all the future PUD locations as they are now valued at $0 and the corresponding volumes that could be produced by drilling these future wells from the Company’s reserve valuation. This happened because it appears unlikely that such wells would be drilled or have value if prices remain at the snapshot end of year 2008 price level for all future periods, as is assumed under current reserve reporting standards.

The Company will report its proved reserves under the new modernization rules enacted by the SEC for the year ending December 31, 2009.

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At year end 2009, it remains possible that if yearly average commodity prices in 2009 are significantly higher (or lower) than the year-end snapshot price for 2008, the Company’s 2009 reserve valuations reserves may correspondingly increase (or decrease) significantly from the year end 2008 valuations, as a result of the same factors set out above. Nevertheless, the Company eagerly awaits the rule changes adopted by the SEC for 2009 as management believes that the new reporting rules and standards will give a more accurate and realistic picture of the Company’s future cash flow values and drilling opportunities both as to PDP and PUD categories of the Company’s reserves as well as adding new reportable categories for probable and possible reserves.

The LaRoche Report using the snapshot analysis method the standardized measure of future net cash flows associated with total proved reserves of the Company as of December 31, 2008 is stated to be $10,923,240. The LaRoche Report indicates the “proven developed producing” reserves for the Company as of December 31, 2008 to be as follows: net production volumes of 1,240,000 barrels of oil and 907 MMCF of gas compared to 1,604,607 barrels of oil and 1,130 MMCF of gas as reported by the Company at the end of 2007. The standardized measure of future net cash flows associated with total proved producing reserves as of December 31, 2008 is stated to be $10,134,445.

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.

The Company has not filed the Report prepared by LaRoche or any other reserve reports with any Federal authority or agency other than the SEC. The Company, however, has filed the information in the Report of the Company's reserves with the Energy Information Service of the Department of Energy in compliance with that agency's statutory function of surveying oil and gas reserves nationwide.

The term "Proved Oil and Gas Reserves" is defined in Rule 4-10(a) (2) of Regulation S-X promulgated by the SEC as follows:

2. Proved oil and gas reserves. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

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i. Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

ii. Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

iii. Estimates of proved reserves do not include the following: (A) oil that may become available from known reservoirs but is classified separately as indicated additional reserves; (B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

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 interests or other parties' working interest.

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KANSAS

Year Ended December 31	**Production**		**Cost of Production (per BOE)** [3]	**Average Sales Price**	
	Oil (Bbl)	**Gas (Mcf)**		**Oil (Bbl)**	**Gas (Per Mcf)**
2008	231,598	-0-	$17.21	$34.04	-0-
2007	178,311	-0-	$16.97	$85.53	-0-
2006	179,556	-0-	$13.05	$56.69	-0-

TENNESSEE

Year Ended December 31	**Production**		**Cost of Production (per BOE)**	**Average Sales Price**	
	Oil (Bbl)	**Gas (Mcf)**		**Oil (Bbl)**	**Gas (Per Mcf)**
2008	6,396	104,043	$22.56	$31.69	$7.00
2007	6,877	117,129	$26.42	$82.71	$7.21
2006	9,633	138,078	$14.97	$54.81	$8.33

Oil and Gas Drilling Activities

Kansas

In 2008, the Company drilled 12 gross new wells in Kansas. These wells included the tenth and final well in the

Company's Ten Well Program. See, Item 1 of this Report. The Company has a 100% working interest in the other eleven wells it drilled in Kansas in 2008. All wells drilled in 2008 have produced in the aggregate a cumulative total of 23,051 barrels of oil.

The results of the wells drilled in Kansas in 2008 are set out in the following table. Other than Kroeker No. 1 well the Company has a 100% working interest in the wells.

NAME OF WELL	DATE COMPLETED	CUMULATIVE PRODUCTION (Bbl)
Kroeker #1	2-28-2008	1,088.00*
McElhaney A #1	4-22-2008	7,197.00
VonLintel #1	4-24-2008	Dry Hole – Plugged (exploratory)
Ruder #1	6-12-2008	468.00
Veverka B #1	7-27-2008	5,916.00
Albers #1	7-25-2008	6,005.00
McClure #1	8-20-2008	Dry Hole – Plugged (exploratory)
Veverka C #1	9-23-2008	Salt Water Disposal Well
Zerger #1	10-29-2008	85.00
Albers A #1	11-13-2008	2,064.00
Veverka B #2	12-4-2008	208.00
Mai A #1	12-10-2008	Dry Hole – Plugged (exploratory)

* Part of the Ten Well Program

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.

Tennessee

In 2008, the Company did not drill any new wells in the Swan Creek Field. The Company has signed a farmout agreement allowing the drilling of shale gas wells in leased areas surrounding but outside of the Swan Creek Field. See Item 1, The Tennessee Properties, Swan Creek Production and Development, above. 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.

Gross and Net Wells

The following tables set forth for the fiscal years ending December 31, 2006, 2007 and 2008 the number of gross and net development wells drilled by the Company. The wells drilled in 2008 refer to the tenth and final well drilled in the Ten Well Program as well as eleven other wells drilled in Kansas in which the Company has a 100% working interest.

The term gross wells means the total number of wells in which the Company owns an interest, while the term net wells means the sum of the fractional working interests the Company owns in the gross wells.

	YEAR ENDED DECEMBER 31					
	2008		2007		2006	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Kansas						
Productive Wells	9	7.725	10	4.0	9	5.055
Dry Holes	3	2.625	6	5.25	1	0.56
Tennessee						
Productive Wells	0	0	0	0	0	0
Dry Holes	0	0	0	0	0	0

<u>Productive Wells</u>

The following table sets forth information regarding the number of productive wells in which the Company held a working interest as of December 31, 2008. 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	0	0	184	142
Tennessee	21	16.3	4	3.5

<u>Developed and Undeveloped Oil and Gas Acreage</u>

As of December 31, 2008 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	14,761	12,000	15,490	12,700
Tennessee	3,120	2,370	5,515	3,822

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. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None during the fourth quarter of 2008.

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 Alternext US exchange under the symbol TGC. The Company's common stock was previously listed under the symbol TGC on the American Stock Exchange ("AMEX") until its acquisition by NYSE in October 2008. The range of high and low closing prices for shares of common stock of the Company as reported on the AMEX and NYSE Alternext US during the fiscal years ended December 31, 2008 and December 31, 2007 are set forth below.

	High	Low
For the Quarters Ending		
March 31, 2008	$ 0.68	$ 0.51
June 30, 2008	2.67	0.56
September 30, 2008	2.99	0.94
December 31, 2008	1.01	0.48
March 31, 2007	$ 0.83	$ 0.69
June 30, 2007	0.76	0.59
September 30, 2007	0.80	0.59
December 31, 2007	0.81	0.50

Holders

As of March 2, 2008 the number of shareholders of record of the Company's common stock was 336 and management believes that there are approximately 10,474 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 2008 and has no present plans to declare any further dividends with respect to its common stock.

Recent Sales of Unregistered Securities

During the fourth quarter of fiscal 2008, 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 2008 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 2008.

Equity Compensation Plan Information

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

Performance Graph

The graph below compares the cumulative total stockholder return on the Company's common stock with the cumulative total stockholder return of (1) the AMEX Index and (2) the Standard Industrial Code Index for the Crude Petroleum and Natural Gas Industry , assuming an investment in each of $100 on December 31, 2003. The performance graph represents past performance and should not be considered to be an indication of future performance.

COMPARISON OF CUMULATIVE TOTAL RETURN OF ONE OR MORE COMPANIES, PEER GROUPS, INDUSTRY INDEXES AND/OR BROAD MARKETS

FISCAL YEAR ENDING

COMPANY/INDEX/MARKET	**12/31/2003**	**12/31/2004**	**12/30/2005**	**12/29/2006**	**12/31/2007**	**12/31/2008**
Tengasco Incorporated	**100.00**	**34.67**	**53.33**	**93.33**	**66.67**	**82.67**
Crude Petroleum & Natural Gas	**100.00**	**127.03**	**182.51**	**237.31**	**333.59**	**195.20**
AMEX Market Index	**100.00**	**114.51**	**126.29**	**141.39**	**158.74**	**94.93**

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.

Year Ended December 31,

	2008	**2007**	**2006**	**2005**	**2004**
Income Statement Data:					
Oil and Gas Revenues	$15,569,904	$9,300,144	$8,896,036	$7,067,790	$6,013,374
Production Cost and Taxes	$5,887,869	$4,322,833	$3,287,233	$3,046,460	$3,364,429
General and Administrative	$1,862,941	$1,417,001	$1,293,109	$1,322,616	$1,777,183
Interest Expense	$608,096	$ 333,198	$ 168,590	$472,655	$1,367,180
Net Income	$169,662	$3,510,322	$2,141,364	$1,088,028	$(1,994,025)
Net Income Attributable to Common Stockholders	$169,662	$3,510,322	$2,141,364	$1,088,028	$(1,994,025)
Net Income Attributable to Common Stockholder Per Share	$ 0.00	$ 0.06	$ 0.04	$ 0.02	$ (0.05)

Year Ended December 31,[4]

	2008	**2007**	**2006**	**2005**	**2004**
Balance Sheet Data:					
Working Capital Surplus (Deficit)	$647,156	$2,473,476[5]	$872,507	$(1,334,744)	$(6,753,721)
Oil and Gas Properties, Net	$14,141,698	$16,939,543	$12,703,629	$ 9,675,977	$12,826,903
Pipeline Facilities, Net	$12,379,642	$12,916,667	$13,460,667	$ 13,994,453	$14,602,639
Total Assets	$42,446,607	$38,011,491	$28,454,338	$ 25,908,616	$28,209,749

Long-Term Debt	$10,052,023	$ 4,315,773	$ 2,730,534	$ 117,912	$ 1,940,890
Redeemable Preferred Stock	$ -0-	$ -0-	$ -0-	$ -0-	$ -0-
Stockholders Equity	$28,575,530	$28,102,871	$ 24,420,205	$21,961,454	$18,349,687

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 $169,662 or $0.00 per share in 2008 compared to a net income of $3,510,322 or $0.06 per share in 2007 and compared to a net income of $2,141,364 or $0.04 per share in 2006. The Company had income from operations (before ceiling test write-down) of $4,777,179; however, the Company had an $11,608,397 ceiling test writedown, ($7.7 million net of tax effects) on its oil and gas properties. See Note 1 to Consolidated Financial Statements.

The Company recognized a tax benefit for net operating loss carry forwards in the amount of $2,100,000 in 2007 and $5,227,000 in 2008.

The Company realized revenues of $15,600,674 in 2008 compared to $9,368,624 in 2007 and compared to $9,001,681 in 2006. Revenues increased $6,232,050 from 2007 due to an increase in oil prices in Kansas as prices averaged $92.69 in 2008 compared to $66.42 in 2007 and an increase in production in Kansas from 182,471 bbls in 2007 to 235,481 bbls in 2008.

Gas prices received for sales of gas from the Swan Creek Field averaged $9.10 per Mcf in 2008, $6.86 per Mcf in 2007 and $7.27 per Mcf in 2006. Oil prices received for sales of oil from the Swan Creek field averaged $80.20 per barrel in 2008, $64.81 per barrel in 2007 and $60.39 per barrel in 2006.

Production costs and taxes in 2008 increased to $5,887,869 from $4,322,833 in 2007 and $3,287,233 in 2006. The difference is due to increased work-overs of wells to increase production, increased taxes, and overall cost increases of supplies in the industry.

Depletion, depreciation, and amortization for 2008 was $2,159,505, an increase from $1,631,468 in 2007 due to production volumes added to future reserves from drilling activities. Depletion, depreciation, and amortization was $1,911,416 in 2006. The increase in 2008 is due to increase in volumes produced in 2008.

The Company's general and administrative costs of $1,862,941 in 2008 increased from 2007 levels of $1,417,001 and 2006 level of $1,293,109. The 2008, 2007, and 2006 costs included non-cash charges related to stock options of $231,127, $116,476 and $159,160, respectively.

The increase in interest expense in 2008 relates to the borrowing base increase of the Sovereign credit facility. Interest expense in 2008 was $608,096, $333,198 in 2007 and $168,590 in 2006.

The Company's public relations costs were $41,090 for 2008, compared to $21,605 for 2007 and $26,037 for 2006.

Professional fees in 2008 were $263,994 compared to $232,197 in 2007. This increase was due to the Company commencing its review of its internal controls over its financial reporting. Professional fees in 2006 were $173,932.

The Company recorded a deferred tax asset of $2,100,000 in 2007 relating to the Company's net operating loss carry forwards and $5,227,000 in 2008 with $1,623,995 recognized as income tax expense.

Liquidity and Capital Resources

On June 29, 2006, the Company closed a $50,000,000 revolving senior credit facility between the Company and Citibank Texas, N.A. ("Citibank"). Under the facility, loans and letters of credit were available to the Company on a revolving basis in an amount outstanding not to exceed the lesser of $50,000,000 or the borrowing base in effect from time to time.

On December 17, 2007, Citibank assigned the Company's revolving credit facility with Citibank to Sovereign Bank of Dallas, Texas ("Sovereign") as requested by the Company. Under the facility as assigned to Sovereign, loans and letters of credit are available to the Company on a revolving basis in an amount outstanding not to exceed the lesser of $20 million or the Company's borrowing base in effect from time to time. The Sovereign 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 Company's initial borrowing base with Sovereign was set at $7.0 million, an increase from its borrowing base of $3.3 million with Citibank prior to the assignment.

On June 2, 2008, the Company entered into an amendment to its credit facility with Sovereign whereby the Company's borrowing base was increased by the Bank as a result of its review of the Company's currently owned producing properties. The borrowing base was raised to $11 million effective June 2, 2008. The Company has previously utilized about $4.2 million of the facility, leaving approximately $6.8 million available for use by the Company upon this borrowing base increase. The Company used $5.35 million of the then available $6.8 million for the purchase of the Riffe Field properties in Kansas. The total borrowing by the Company under the facility at year-end 2008 and as of the date of this Report is $9.9 million.

Effective February 5, 2009, the Company amended its credit facility with Sovereign to provide for a monthly reduction of the Bank's commitment by $150,000 per month for the five month period of February through June 2008. This commitment reduction is not a cash payment obligation of the Company but has the effect of reducing the Company's available borrowing base in monthly increments of $150,000 so that by June 2009 the Company's available borrowing base under the Sovereign facility will be reduced by $750,000 from $11.0 million to $10.25 million. The Company's borrowing base will be redetermined at the next regularly scheduled borrowing base review on June 15, 2009. At that time, the borrowing base is subject to be redetermined according to the parameters established by Sovereign and applied to all of its borrowers.

Although the Company has not been required as of the date of this Report to make any payment on principal to

Sovereign Bank under the borrowing base in effect at any time, the Company can make no assurance that in view of the current conditions in the national and world economies, including the realistic possibility of continued low commodity prices being received for the Company's oil and gas production for extended periods, that Sovereign may in the future make a redetermination of the Company's borrowing base to a point below the level of the Company's current borrowing. In such an event, the Company may be called upon to make installment or other payments in such amount and at such times to Sovereign 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.

Although the year 2008 ended in challenging fashion, during the entire year the Company remained focused on production and carefully used its cash flows and available credit to do so.

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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 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 for 2008 was $7,129,728 compared to $3,446,677 in 2007. The Company's net income in 2008 of $169,662 compared to net income of $3,510,322 in 2007 was the result of an $11,608,397 impairment asset write-down in 2008. The impact on cash provided by operating activities was due to the net loss for 2008 and was increased by non-cash depletion, depreciation, and amortization of $2,159,505 and by non-cash compensation and services paid by insurance of equity instruments of $231,127. Cash flow used in working capital items in 2008 was ($203,131) compared to cash provided by working capital items of $211,742 in 2007. The Company's net income for 2007 included a non-cash deferred tax asset for net operating loss carry forwards of $2,100,000 in 2007 and a net tax benefit of $ 7,000,880 in 2008.

Net cash provided by operating activities for 2007 was $3,446,677 compared to $4,353,966 in 2006. The Company's net income in 2007 increased to $3,510,322 from $2,141,364 in 2006. The impact on cash provided by operating activities was due to the net income for 2007 and was increased by non-cash depletion, depreciation, and amortization of $1,631,468 and by non-cash compensation and services paid by insurance of equity instruments of $116,476. Cash flow provided in working capital items in 2007 was $211,742 compared to cash provided by working capital items of $122,152 in 2006. The Company's net income for 2007 included a non-cash deferred tax asset for net operating loss carry forwards of $2,100,000.

Net cash used in investing activities amounted to $14,867,783 for 2008 compared to $3,145,764 for 2007. The increase in 2008 was primarily attributable to an increase in oil and gas properties of $11,964,414 and an increase in additions to methane project of $2,707,065.

Net cash used in investing activities amounted to $3,145,764 for 2007 compared to $4,413,185 for 2006. The decrease in 2006 was primarily attributable to an increase in oil and gas properties of $5,190,611 offset by drilling program funds received of $3,850,000 and an increase in additions to methane project of $1,649,710.

Net cash provided by financing activities increased to $5,755,974 in 2008 from $1,556,261 in 2007. In 2008, the primary sources of financing included proceeds from borrowings of $5,889,330 compared to $1,696,444 in 2007.

Net cash provided by financing activities increased to $1,556,261 in 2007 from $167,915 in 2006. In 2007, the primary sources of financing included proceeds from borrowings of $1,696,444compared to $2,732,145 in 2006. The primary use of cash in financing activities in 2006 was to repay the drilling program liability of $2,324,400.

Critical Accounting Policies

The Company prepares its Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America, which requires 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

The Company recognizes revenues based on actual volumes of oil and gas sold and delivered to its customers. Natural gas meters are placed at the customers’ location and usage is billed each month. Crude oil is stored and at the time of delivery to the purchasers, revenues are recognized.

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 productive and non-productive costs incurred in connection with the acquisition of, exploration for and development of oil and gas reserves for each cost center are capitalized. Capitalized costs include lease acquisitions, geological and geophysical work, day rate rentals and the costs of drilling, completing and equipping oil and gas wells. Costs, however, associated with production and general corporate activities are expensed in the period incurred. Interest costs related to unproved properties and properties under development are also capitalized to oil and gas properties. Gains or losses are recognized only upon sales or dispositions of significant amounts of oil and gas reserves representing an entire cost center. Proceeds from all other sales or dispositions are treated as reductions to capitalized costs. The capitalized oil and gas property, less accumulated depreciation, depletion and amortization and related deferred income taxes, if any, are generally limited to an amount (the ceiling limitation) equal to the sum of: (a) the present value of estimated future net revenues computed by applying current prices in effect as of the balance sheet date (with consideration of price changes only to the extent provided by contractual arrangements) to estimated future production of proved oil and gas reserves, less estimated future expenditures (based on current costs) to be incurred in developing and producing the reserves using a discount factor of 10% and assuming continuation of existing economic conditions; and

(b) the cost of investments in unevaluated properties excluded from the costs being amortized. No ceiling write-downs were recorded in 2007 and 2006. However, in 2008 the Company incurred a ceiling limitation write-down in the amount of $11,608,397 due to the dramatically lower year-end oil prices in 2008 as compared to 2007 and the resulting significant downward adjustment of the Company’s estimated proved reserves. The effect of the ceiling write-down resulted in the Company recording a net income in 2008 of $169,662 despite having an operating profit in

2008 of $4,777,179 before the ceiling test write-down.

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 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, 2008 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 is required to record the effects of contractual or other legal obligations on well abandonments for capping and plugging wells. Management periodically reviews the estimate of the timing of the wells' closure as well as the estimated closing costs, discounted at the credit adjusted risk free rate of 12%. Quarterly, management accretes the 12% discount into the liability and makes other adjustments to the liability for well retirements incurred during the period.

Recent Accounting Pronouncements

In July 2006, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement 109" ("FIN 48"), which clarifies the accounting for uncertainty in tax positions taken or expected to be taken in a tax return, including issues relating to financial statement recognition and measurement. FIN 48 provides that the tax effects from an uncertain tax position can be recognized in the financial statements only if the position is "more-likely-than-not" to be sustained if the position were to be challenged by a taxing authority.

The assessment of the tax position is based solely on the technical merits of the position, without regard to the likelihood that the tax position may be challenged. If an uncertain tax position meets the "more-likely-than-not" threshold, the largest amount of tax benefit that is more than 50 percent likely to be recognized upon ultimate settlement with the taxing authority, is recorded. The provisions of FIN 48 are effective for fiscal years beginning after December 15, 2006, with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. Consistent with the requirements of FIN 48, we adopted FIN 48 on January 1, 2007. The adoption of FIN 48 had no impact on our results of operations or financial position. The Company currently has open tax return periods beginning with December 31, 2005 through December 31, 2007.

In September 2006, the Securities and Exchange Commission staff published Staff Accounting Bulletin SAB No. 108 ("SAB 108"), "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in

Current Year Financial Statements." SAB 108 addresses quantifying the financial statement effects of misstatements, specifically, how the effects of prior year uncorrected errors must be considered in quantifying misstatements in the current year financial statements. SAB 108 is effective for fiscal years ending after November 15, 2006. The Company adopted SAB 108 in the fourth quarter of 2006. Adoption did not have an impact on the Company’s consolidated financial statements.

In September 2006, the FASB issued No. SFAS 157, “Fair Value Measurements” (“SFAS 157”). The standard provides guidance for using fair value to measure assets and liabilities. It defines fair value, establishes a framework for measuring fair value under generally accepted accounting principles and expands disclosures about fair value measurement. Under the standard, fair value refers to the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the market in which the reporting entity transacts. It clarifies the principle that fair value should be based on the assumptions market participants would use when pricing the asset or liability. In support of this principle, the standard establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. Under the standard, fair value measurements would be separately disclosed by level within the fair value hierarchy. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007. The Company adopted SFAS 157 effective January 1, 2008. Adoption of this statement did not have a material impact on the Company’s financial condition, results of operations and cash flows.

In February 2007, the FASB issued SFAS No. 159 “The Fair Value Option for Financial Assets and Financial Liabilities — as amended (“SFAS 159”). SFAS 159 permits entities to elect to report eligible financial instruments at fair value subject to conditions stated in the pronouncement including adoption of SFAS 157 discussed above. The purpose of SFAS 159 is to improve financial reporting by mitigating volatility in earnings related to current reporting requirements. The Company considered the applicability of SFAS 159 and determined not to adopt it at this time.

CONTRACTUAL OBLIGATIONS

The following table summarizes the Company’s contractual obligations at December 31, 2008:

Payments Due By Period

Contractual Obligations	Total	Less than 1year	1-3 years	3-5 years	More than 5 years
Long-Term Debt Obligations[6]	$10,126,900	$74,877	$10,052,023	$-0-	$-0-
Capital Lease Obligations	$-0-	$-0-	$-0-	$-0-	$-0-
Operating Lease Obligations[7]	$-0-	$-0-	$-0-	$-0-	$-0-
Purchase Obligations	$-0-	$-0-	$-0-	$-0-	$-0-
Other Long-Term Liabilities	$-0-	$-0-	$-0-	$-0-	$-0-
Total	$10,126,900	$74,877	$10,052,023	$-0-	$-0-

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 $31.69 per barrel to a high of $127.29 per barrel during 2008. Gas price realizations ranged from a monthly low of $6.47 per Mcf to a monthly high of $13.21 per Mcf during the same period. The Company did not enter into any hedging agreements in 2008 to limit exposure to oil and gas price fluctuations.

Interest Rate Risk

At December 31, 2008, the Company had debt outstanding of approximately $10,126,900 including, as of that date, $9,900,000 owed on its credit facility with Sovereign Bank. The interest rate on the credit facility is variable at a rate equal to LIBOR plus 2.5% with a floor of 6%. The Company’s remaining debt of $226,900 has fixed interest rates ranging from 5.5% to 8.25%.

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As a result, the Company's annual interest costs in 2008 fluctuated based on short-term interest rates on approximately 98% of its total debt outstanding at December 31, 2008. The impact on interest expense and the Company’s cash flows of a 10 percent increase in the interest rate on the Sovereign Bank credit facility would be approximately $60,000, assuming borrowed amounts under the credit facility remained at the same amount owed as of December 31, 2008. The Company did not have any open derivative contracts relating to interest rates at December 31, 2008.

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 could 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's financial position, results of operations and cash flows.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS

ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure 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)).

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

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.

Management's 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.

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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's internal control over financial reporting as of December 31, 2008. 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, 2008.

The Company's independent registered public accounting firm, Rodefer Moss & Co, PLLC, has issued an attestation report on the effectiveness of the Company's internal controls over financial reporting. This report appears below.

Report of Independent Registered Public Accounting Firm on

Internal Controls Over Financial Reporting

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Tengasco, Inc.

We have audited Tengasco, Inc.'s internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Tengasco, Inc.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying "Management's Report on Internal Control Over Financial Reporting." Our responsibility is to express an opinion on the company's internal control over financial reporting 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, Tengasco, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Tengasco, Inc. as of December 31, 2008 and 2007, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2008 and our report dated March 13, 2009, expressed an unqualified opinion thereon.

/s/ Rodefer Moss & Co, PLLC
Certified Public Accountants
Knoxville, Tennessee
March 16, 2009

Changes in Internal Controls

There have been no changes to the Company's system of internal control over financial reporting during the year ended December 31, 2008 that has materially affected, or is reasonably likely to materially affect, the Company's system of controls 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.

ITEM 9B. OTHER INFORMATION

The Company's 2009 Annual Meeting of Stockholders will be held on June 1, 2009 at 9:00 a.m. at the Homewood Suites by Hilton, 10935 Turkey Drive, Knoxville, Tennessee 37922.

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 2009 Annual Meeting of Stockholders (the "Proxy Statement").

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

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 STOCKHOLDER 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, 2008.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding, options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders	2,931,000	$0.38	3,049,368
Equity compensation plans not approved by security holders[8]	0	n/a	0
Total	2,441,000	$0.30	39,638

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

The information required by this Item as to transactions 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 ACCOUNTANTS 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 Rodefer Moss & Co, PLLC as Independent Auditors" in the Proxy Statement.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

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

1. Financial Statements:

Consolidated Balance Sheets
Consolidated Income Statements
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:

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Exhibit Index

Exhibit Number	Description
3.1	Charter (Incorporated by reference to Exhibit 3.7 to the registrant's registration statement on Form 10-SB filed August 7, 1997 (the "Form 10-SB"))
3.2	Articles of Merger and Plan of Merger (taking into account the formation of the Tennessee wholly-owned subsidiary for the purpose of changing the Company's domicile and effecting reverse split) (Incorporated by reference to Exhibit 3.8 to the Form 10-SB)
3.3	Articles of Amendment to the Charter dated June 24, 1998 (Incorporated by reference to Exhibit 3.9 to the registrant's annual report on Form 10-KSB filed April 15, 1999 (the "1998 Form 10-KSB"))
3.4	Articles of Amendment to the Charter dated October 30, 1998 (Incorporated by reference to Exhibit 3.10 to the 1998 Form 10-KSB)
3.5	Articles of Amendment to the Charter filed March 17, 2000 (Incorporated by reference to Exhibit 3.11 to the registrant's annual report on Form 10-KSB filed April 14, 2000 (the "1999 Form 10-KSB"))
3.6	By-laws (Incorporated by reference to Exhibit 3.2 to the Form 10-SB)
3.7	Amendment and Restated By-laws dated May 19, 2005 (Incorporated by reference to the registrant's annual report on Form 10-K for the year ended December 31, 2005)
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	Natural Gas Sales Agreement between Tengasco, Inc. and BAE SYSTEMS Ordnance Systems Inc. dated March 30, 2001 (Incorporated by reference to Exhibit 10.20 to the 2000 Form 10-KSB)
10.4	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)
10.5	Promissory Note made by Tengasco, Inc. and Tengasco Pipeline Corporation to Dolphin Offshore Partners, LP dated May 18, 2004 in the principal amount of $2,500,000 (Incorporated by reference to Exhibit 10.47 to the registrant's quarterly report on Form 10-Q filed May 20, 2004)
10.6	Promissory Note made by Tengasco, Inc. and Tengasco Pipeline Corporation to Dolphin Offshore Partners, LP dated December 30, 2004 in the principal amount of $550,000 (Incorporated by reference from to Exhibit 10.19 to the registrant's Annual Report on Form 10-K filed March 31, 2005)
10.7	Amended and Restated Promissory Note made by Tengasco, Inc. and Tengasco Pipeline Corporation to Dolphin Offshore Partners, LP dated May 19, 2005 in the principal amount of $700,000 ((Incorporated by reference to Exhibit 10.1 to the

	registrant's current report on Form 8-K dated May 23, 2005)
10.8	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)
10.9	Promissory Note made by Tengasco, Inc. and Tengasco Pipeline Corporation to Dolphin Offshore Partners, LP dated August 22, 2005 in the principal amount of $1,814,000 (Incorporated by reference to Exhibit 10.1 to the registrant's current report on Form 8-K dated August 22, 2005 (the "August 22, 2005 8-K"))
10.10	Amended and Restated Promissory Note made by Tengasco, Inc. and Tengasco Pipeline Corporation dated August 18, 2005 in the principal amount of $700,000 (Incorporated by reference to Exhibit 10.2 to the August 22, 2005 8-K.)
10.11	Subscription Agreement of Hoactzin Partners, L.P. for a 94.275% working interest in the Company's twelve well drilling program on its Kansas Properties. (Incorporated by reference to Exhibit 10.1 to the registrant's current report on Form 8-K dated October 5, 2005)
10.12	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)
10.13	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"])..
10.14	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).
10.15	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).
10.16	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).
10.17	Employment Agreement dated December 18, 2007 between Tengasco, Inc. and Charles Patrick McInturff (Incorporated by reference to Exhibit 10.1 to the registrant's current report on Form 8-K dated December 18, 2007)
10.18	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).
10.19	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)
10.20	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).
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.

31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a)
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

* 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 16, 2009

TENGASCO, INC.
(Registrant)

By: s/Jeffrey R. Bailey
Jeffrey R. Bailey,
Chief Executive Officer

By: s/Mark A. Ruth
Mark A. Ruth,
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 16, 2009
s/Matthew K. Behrent Matthew K. Behrent	Director	March 16, 2009
s/John A. Clendening John A. Clendening	Director	March 16, 2009
s/Carlos P. Salas Carlos P. Salas	Director	March 16, 2009
s/Peter E. Salas Peter E. Salas	Director	March 16, 2009
s/Mark A. Ruth Mark A. Ruth	Principal and Financial Accounting Officer	March 16, 2009

[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 2009 Annual Meeting of Stockholders.

[3] A "BOE is a barrel of oil equivalent. A barrel of oil contains approximately 6 Mcf of natural gas by heating content. The volumes of gas produced have been converted into "barrels of oil equivalent" for the purposes of calculating costs of production.

[4] No cash dividends have been declared or paid by the Company for the periods presented.

[5] The Company's working capital surplus of $2,473.476 was attributable to high commodity prices as well as an increase in the borrowing base by $900,000 on December 17, 2007 and the funding of the Ten Well Program. The Company expended approximately $1.5 million of these funds subsequent to year-end on the Methane Project and completing the Ten Well Program.

[6] See, Note 7 to Consolidated Financial Statements in Item 8 of this Report.

[7] See, Note 8 to Consolidated Financial Statements in Item 8 of this Report.

[8] 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 to 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'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.

Tengasco, Inc.
and Subsidiaries

Consolidated Financial Statements

Years Ended December 31, 2008, 2007 and 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders

Tengasco, Inc.

We have audited the accompanying consolidated balance sheets of Tengasco, Inc. and subsidiaries as of December 31, 2008 and 2007 and the related consolidated statements of operations, changes in stockholders' equity, and cash flows for the three years 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 audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Tengasco, Inc. as of December 31, 2008 and 2007, and the consolidated results of their operations and their cash flows for the three years then ended in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the Standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Tengasco Inc.'s internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 13, 2009, expressed an unqualified opinion thereon.

/s/ Rodefer Moss & Co, PLLC

Certified Public Accountants

Knoxville, Tennessee

March 16, 2009

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Tengasco, Inc. and Subsidiaries

Consolidated Balance Sheets

December 31,	**2008**	2007
Assets		
e		
Current		
Cash and cash equivalents	$ **244,758**	$ 2,226,839
Accounts receivable	**1,104,257**	1,057,148
Participant receivables	**24,607**	49,872
Inventory	**475,640**	460,365
Other current assets	**11,056**	11,056
Total current assets	**1,860,318**	3,805,280
Restricted cash	**120,500**	120,500
Loan fees	**201,719**	223,733
Oil and gas properties, net (on the basis of full cost accounting)	**14,141,698**	16,939,543
Pipeline facilities, net of accumulated Depreciation of $3,967,099 and $3,423,099	**12,379,642**	12,916,667
Other property and equipment, net	**285,075**	256,058
Deferred Tax Asset	**9,100,880**	2,100,000
Methane Project	**4,356,775**	1,649,710
	$ 42,446,607	$ 38,011,491

See accompanying Notes to Consolidated Financial Statements

Tengasco, Inc. and Subsidiaries

Consolidated Balance Sheets

December 31,	**2008**	2007
Liabilities and Stockholders' Equity		
Current liabilities		
Current maturities of long term debt	**$ 74,877**	$ 57,887
Accounts payable	**701,086**	903,238
Accrued interest payable	**-**	10,005
Other accrued liabilities	**437,199**	360,674
Total current liabilities	**1,213,162**	1,331,804
Asset retirement obligations	**655,727**	531,101
Deferred Conveyance		
Oil & Gas Properties	**1,097,165**	2,876,942
Prepaid Revenues	**853,000**	853,000
Long term debt, less current maturities	**10,052,023**	4,315,773
Total liabilities	**13,871,077**	9,908,620
Stockholders' equity		
Common stock, $.001 par value; authorized 100,000,000 shares; 59,350,661 and 59,155,750 shares issued and outstanding	**59,351**	59,156
Additional paid-in capital	**54,992,327**	54,689,525
Accumulated deficit	**(26,476,148)**	(26,645,810)
Total Stockholders' equity	**28,575,530**	28,102,871
	$ 42,446,607	$ 38,011,491

See accompanying Notes to Consolidated Financial Statements

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Tengasco, Inc. and Subsidiaries

Consolidated Statements of Operations

Years ended December 31,	**2008**	**2007**	**2006**
Revenues and other income			
Oil and gas revenues	**$15,569,904**	$9,300,144	$8,896,036
Pipeline transportation revenues	**11,804**	51,492	87,822
Interest Income	**18,966**	16,988	17,823
Total revenues and other income	**15,600,674**	9,368,624	9,001,681
Costs and expenses			
Production costs and taxes	**5,887,869**	4,322,833	3,287,233
Depreciation, depletion and amortization	**2,159,505**	1,631,468	1,911,416
Ceiling Test Impairment	**(11,608,397)**	-	-
General and administrative	**1,862,941**	1,417,001	1,293,109
Interest expense	**608,096**	333,198	168,590
Public relations	**41,090**	21,605	26,037
Professional fees	**263,994**	232,197	173,932
Total costs and expenses	**22,431,892**	7,958,302	6,860,317
Net Operating (Loss)/Income	**(6,831,218)**	1,410,322	2,141,364
Deferred Tax Benefit	**8,624,875**	2,100,000	-
Income Tax Expense	**(1,623,995)**	-	-
Net Income	**$169,662**	$3,510,322	$2,141,364
Net Income per share			
Basic and diluted:			
Operations	**$ 0.00**	$ 0.06	$ 0.04
Total	**$ 0.00**	$ 0.06	$ 0.04
Shares used in computing earnings per share			
Basic	**59,248,446**	59,117,176	58,851,883
Diluted	**61,492,446**	60,827,224	60,364,797

See accompanying Notes to Consolidated Financial Statements

Tengasco, Inc. and Subsidiaries

Consolidated Statements of Stockholders' Equity

	Common Stock		*Paid-In*	*Accumulated*	
	Shares	*Amount*	*Capital*	*Deficit*	*Total*
Balance, January 1, 2006,	58,604,678	$58,605	$54,200,345	$(32,297,496)	$21,961,454
Net Income	-	-	-	$ 2,141,364	$ 2,141,364
Options & compensation expense	364,500	365	301,674	—	302,039
Common stock issued for exercise of warrants	34,106	34	15,314	—	15,348
Balance, December 31, 2006	59,003,284	59,004	54,517,333	(30,156)132)	24,420,205
Net Income	-	-	-	3,510,322	3,510,322
Options & compensation expense	145,250	145	168,951	-	169,096
Common stock issued for exercise of warrants	7,216	7	3,241	-	3,248
Balance, December 31, 2007	59,155,750	59,156	54,689,525	(26,645,810)	28,102,871
Net Income	-	-	-	169,662	169,662
Options Granted	-	-	212,827	-	212,827
Shares Issued for compensation	30,000	30	18,270	-	18,300
Shares Issued for Exercise of Options of warrants	164,911	165	71,705	-	71,870
Balance, December 31, 2008	59,350,661	$59,351	$54,992,327	$ (26,476,148)	$28,575,530

See accompanying Notes to Consolidated Financial Statements

Tengasco, Inc. and Subsidiaries

Consolidated Statements of Cash Flows

	2008	2007	2006
Operating activities			
Net Income	$169,662	$ 3,510,322	$ 2,141,364
Adjustments to reconcile net income to net cash			
Provided by operating activities:			
Depletion, depreciation, and amortization	2,159,505	1,631,468	1,911,416
Accretion on Asset Retirement Obligation	155,006	70,929	42,340
Ceiling Test Impairment	11,608,397	-	-
(Gain)/loss on sale of vehicles/equipment	10,042	5,740	(22,466)
Compensation and services paid in stock options	231,127	116,476	159,160
Deferred Tax Benefit	(7,000,880)	(2,100,000)	-
Changes in assets and liabilities:			
Accounts receivable	(47,109)	(337,308)	434,565
Participant receivables	25,265	(36,864)	(3,231)
Other current assets	-	-	(5,000)
Inventory	(15,275)	90,157	(54,191)
Accounts payable	(202,152)	215,763	90,197
Accrued interest payable	(10,005)	1,573	8,432
Other accrued liabilities	76,525	330,264	(251,327)
Settlement on Asset Retirement Obligations	(30,380)	(51,843)	(97,293)
Net cash provided by operating activities	7,129,728	3,446,677	4,353,966
Investing activities			
Additions to other property & equipment	(189,329)	(172,443)	(137,924)
Restricted cash	-	-	(120,500)
Decrease to other property & equipment	-	17,000	27,915
Net additions to oil and gas properties	(11,964,414)	(5,190,611)	(5,239,862)
Additions to Methane Project	(2,707,065)	(1,649,710)	-
Drilling program portion of additional drilling	-	3,850,000	1,067,400
(Increase)/decrease in pipeline facilities	(6,975)	-	(10,214)
Net cash (used in) investing activities	(14,867,783)	(3,145,764)	(4,413,185)
Financing activities			
Proceeds from exercise of options/warrants	71,870	55,867	158,227
Proceeds from borrowings	5,889,330	1,696,444	2,732,145
Loan fees	(69,137)	(77,467)	(285,224)
Borrowings	(136,089)	(118,583)	(112,833)
Decrease in Drilling Program liability	-	-	(2,324,400)
Net cash provided by financing activities	5,755,974	1,556,261	167,915
Net change in cash and cash equivalents	(1,982,081)	1,857,174	108,696
Cash and cash equivalents, beginning of period	2,226,839	369,665	260,969
Cash and cash equivalents, end of period	$ 244,758	$ 2,226,839	$ 369,665

Tengasco, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

The Company was initially organized in Utah in 1916 for the purpose of mining, reducing and smelting mineral ores, under the name Gold Deposit Mining & Milling Company, later changed to Onasco Companies, Inc. In 1995, the Company changed its name from Onasco Companies, Inc. to Tengasco, Inc., by merging into Tengasco, Inc., a Tennessee corporation, formed by the Company.

The Company is in the business of exploring for and producing oil and natural gas in Kansas and Tennessee. The Company leases producing and non-producing properties with a view toward exploration and development. Emphasis is also placed on pipeline and other infrastructure facilities to provide transportation services. The Company utilizes seismic technology to improve the recovery of reserves.

The Company’s primary area of production and development is in Kansas. The Company’s activities in Kansas commenced in 1998 when it acquired approximately 32,000 acres of leases and production in the vicinity of Hays, Kansas (the “Kansas Properties”). During 2008, the Kansas Properties produced an average of 19,632 gross barrels of oil per month.

The Company’s activities in oil and gas leases in Tennessee are located in Hancock, Claiborne, and Jackson counties. The Company has drilled primarily on a portion of its leases known as the Swan Creek Field in Hancock County focused within what is known as the Knox Formation, one of the geologic formations in that field. During 2008, the Company sold an average of 215 thousand cubic feet of natural gas per day and 533 barrels of oil per month from 19 producing gas wells and 4 producing oil wells in the Swan Creek Field.

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 formed a wholly-owned subsidiary on December 27, 2006 named Manufactured Methane Corporation for the purpose of owning and operating 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 TPC pipeline system in Tennessee for eventual sale to natural gas customers.

Basis of Presentation

The accompanying consolidated financial statements have been prepared in conformity with accounting principles generally accepted in the United States of

Tengasco, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

America, which contemplate continuation of the Company as a going concern and assume realization of assets and the satisfaction of liabilities in the normal course of business.

The consolidated financial statements include the accounts of the Company, Tengasco Pipeline Corporation, Tennessee Land & Mineral Corporation and Manufactured Methane Corporation. All intercompany balances and transactions have been eliminated.

Use of Estimates

The accompanying consolidated financial statements are prepared in conformity with accounting principles generally accepted in the United States of America which require management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The actual results could differ from those estimates.

Revenue Recognition

The Company uses the sales method of accounting for natural gas and oil revenues. Under this method, revenues are recognized based on actual volumes of oil and gas sold to purchasers. Natural gas meters are placed at the customers' locations and usage is billed monthly.

Cash and Cash Equivalents

The Company considers all investments with a maturity of three months or less when purchased to be cash equivalents.

Inventory

Inventory consists of crude oil in tanks and is carried at lower of cost or market value.

Reclassifications

Certain prior year amounts have been reclassified to conform to current year presentation. See Footnote 4.

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 productive and nonproductive costs incurred in connection with the acquisition of, exploration for and development of oil and gas reserves for each cost center are capitalized. Capitalized

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Notes to Consolidated Financial Statements

costs include lease acquisitions, geological and geophysical work, delay rentals and the costs of drilling, completing, equipping and plugging oil and gas wells. Gains or losses are recognized only upon sales or dispositions of significant amounts of oil and gas reserves representing an entire cost center. Proceeds from all other sales or dispositions are treated as reductions to capitalized costs.

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 estimated salvage value, are amortized on the unit-of-production method based on total proved reserves. The Company currently has $1,242,566 in unevaluated properties as of December 31, 2008. 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 determined its reserves based upon reserve reports provided by LaRoche Petroleum Consultants Ltd. in 2008, 2007 and 2006.

The capitalized oil and gas properties, less accumulated depreciation, depletion and amortization and related deferred income taxes, if any, are generally limited to an amount (the ceiling limitation) equal to the sum of: (a) the present value of estimated future net revenues computed by applying current prices in effect as of the balance sheet date (with consideration of price changes only to the extent provided by contractual arrangements) to estimated future production of proved oil and gas reserves, less estimated future expenditures (based on current costs) to be incurred in developing and producing the reserves using a discount factor of 10% and assuming continuation of existing economic conditions; and (b) the cost of investments in unevaluated properties excluded from the costs being amortized. The Company has adopted an SEC accepted method of calculating the full cost ceiling test whereby the liability recognized under Statement of Financial Accounting Standard No. 143 (“SFAS”) “Accounting for Asset Retirement Obligation” (“SFAS 143”) is netted against property cost and the future abandonment obligations are included in estimated future net cash flows.

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 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%. If net capitalized costs of natural gas and crude oil properties exceed the ceiling limit, the Company must charge the amount of the excess, net of related tax effects to earnings. This is called a "ceiling limitation write-down." 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 one period may not be reversed in a subsequent period even though higher natural gas and crude oil prices may have increased the ceiling applicable

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to the subsequent period. In 2008, the Company did incur a ceiling limitation write-down of $11,608,397 ($7,661,397 net of tax effects) due to the dramatically lower year-end oil prices in 2008 as compared to 2007 and the resulting significant downward adjustment of the Company's estimated proved reserves. The effect of the ceiling write-down resulted in the Company recording a net income in 2008 of $169,662. Excluding the impact of the ceiling test write down, however the Company would have had operating income in 2008 of $4,777,179. In light of recent declines in oil prices and forecasts that such prices may continue at lower levels we cannot assure you that the Company will not experience similar ceiling limitation write-downs in the future.

Pipeline Facilities

The pipeline was placed into service upon its completion on March 8, 2001. The pipeline is being depreciated over its estimated useful life of 30 years beginning at the time it was placed in service.

Other Property and Equipment and Long - Lived Assets

Other property and equipment are 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. Long-lived assets (other than oil and gas properties) are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable.

When evidence indicates that operations will not produce sufficient cash flows to cover the carrying amount of the related asset, a permanent impairment is recorded to adjust the asset to fair value. At December 31, 2008, management believes that carrying amounts of all of the Company's long-lived assets will be fully recovered over the course of the Company's normal future operations.

Stock-Based Compensation

The Company recorded $212,827 in 2008, $100,877 in 2007, and $128,197 in 2006 in compensation expense.

Accounts Receivable

Senior management reviews accounts receivable on a monthly basis to determine if any receivables will potentially be uncollectible. Based on the information available to us, the Company believes no allowance for doubtful accounts as of December 31, 2008 and 2007 is necessary. However, actual write-offs may occur.

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Income Taxes

The Company accounts for income taxes using the "asset and liability method." Accordingly, deferred tax liabilities and assets are determined based on the temporary differences between the financial reporting and tax bases of assets and liabilities, using enacted tax rates in effect for the year in which the differences are expected to reverse. Deferred tax assets arise primarily from net operating loss carry-forwards. Management evaluates the likelihood of realization for such assets at year-end providing a valuation allowance for any such amounts not likely to be recovered in future periods. The Company currently has a net operating loss carry forward of $15.6 million.

As of December 31, 2008, the Company also had a deferred tax asset totaling $3.9 million related to the ceiling test write down of $11.6 million. This deferred tax asset arose from differences between the financial statement carrying value of the Company's oil and gas properties, and its respective income tax basis (temporary differences) in the future based on the reduced depletion expense from the ceiling test write down. To assess the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of this deferred tax asset will be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities,

projected future taxable income and tax planning strategies in making this assessment. Management has determined that it is more likely than not that all of this deferred tax asset will be realized, and accordingly has netted this deferred tax asset to the $11.6 million ceiling test write down to calculate the $7.7 million ceiling test write down net of tax effects. The $3.9 million deferred tax asset related to the ceiling test write down is in addition to the deferred tax assets resulting from the Company's net operating loss carry-forwards.

Concentration of Credit Risk

Financial instruments which potentially subject the Company to concentrations of credit risk consist principally of cash and accounts receivable. At times, such cash in banks is in excess of the FDIC insurance limit.

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

The Company is presently dependent upon a small number of customers for the sale of gas from the Swan Creek Field, principally Eastman Chemical Company and other industrial customers in the Kingsport area with which the Company may enter into gas sales contracts.

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Notes to Consolidated Financial Statements

The Company has entered into contracts to supply two manufacturers with natural gas from the Swan Creek Field (Tennessee) through the Company's pipeline. These customers are the Company's primary customers for natural gas sales. Additionally, the Company sells a majority of its crude oil primarily to two customers, one each in Tennessee and two in Kansas. Although management believes that customers could be replaced in the ordinary course of business, if the present customers were to discontinue business with the Company, it could have a significant adverse effect on the Company's projected results of operations.

In 2008, the Company received 93.6 percent of its revenues from Customer A; 3.5 percent of its revenues from Customer B and 2.5 percent of its revenues from Customer C.

In 2007, the Company received 91.4 percent of its revenues from Customer A; 4.9 percent of its revenues from Customer B; and 3.7 percent of its revenues from Customer C.

In 2006, the Company received 85.7 percent of its revenues from Customer A; 10.1 percent of its revenues from Customer B.

In each of the years 2006 through 2008, the identity of the customers indicated above as either A, B or C was the same from year to year, although the percentage of revenues varied from year to year for those customers.

Income per Common Share

In accordance with Statement of Financial Accounting Standards (SFAS) No. 128, "Earnings Per Share" ("SFAS 128"), basic income per share is based on 59,248,446 59,117,176 and 58,851,883 weighted average shares outstanding for the years ended December 31, 2008, December 31, 2007 and December 31, 2006 respectively. Diluted earnings per common share are computed by dividing income available to common shareholders by the weighted average number of shares of common stock outstanding during the period increased to include the number of additional shares of common stock that would have been outstanding if the dilutive potential shares of common stock had been issued. The dilutive effect of outstanding options and warrants is reflected in diluted earnings per share. The number of dilutive shares outstanding is 2,244,000 for 2008, 1,710,048 for 2007 and 1,512,914 for 2006. These are related to options and warrants.

Fair Values of Financial Instruments

Fair values of cash and cash equivalents, investments and short-term debt approximate their carrying values due to the short period of time to maturity. Fair values of long-term debt are based on quoted market prices or pricing models using current market rates, which approximate carrying values.

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Notes to Consolidated Financial Statements

2. Recent Accounting Pronouncements

In July 2006, the Financial Accounting Standards Board (“FASB”) issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement 109" ("FIN 48"), which clarifies the accounting for uncertainty in tax positions taken or expected to be taken in a tax return, including issues relating to financial statement recognition and measurement. FIN 48 provides that the tax effects from an uncertain tax position can be recognized in the financial statements only if the position is "more-likely-than-not" to be sustained if the position were to be challenged by a taxing authority. The assessment of the tax position is based solely on the technical merits of the position, without regard to the likelihood that the tax position may be challenged. If an uncertain tax position meets the "more-likely-than-not" threshold, the largest amount of tax benefit that is more than 50 percent likely to be recognized upon ultimate settlement with the taxing authority, is recorded. The provisions of FIN 48 are effective for fiscal years beginning after December 15, 2006, with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. Consistent with the requirements of FIN 48, we adopted FIN 48 on January 1, 2007. The adoption of FIN 48 had no impact on our results of operations or financial position. The Company currently has open tax return periods beginning with December 31, 2005 through December 31, 2007.

In September 2006, the Securities and Exchange Commission staff published Staff Accounting Bulletin SAB No. 108 (“SAB 108”), "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements." SAB 108 addresses quantifying the financial statement effects of misstatements, specifically, how the effects of prior year uncorrected errors must be considered in quantifying misstatements in the current year financial statements. SAB 108 is effective for fiscal years ending after November 15, 2006. The Company adopted SAB 108 in the fourth quarter of 2006. Adoption did not have an impact on the Company’s consolidated financial statements.

In September 2006, the FASB issued No. SFAS 157, “Fair Value Measurements” (“SFAS 157”). The standard provides guidance for using fair value to measure assets and liabilities. It defines fair value, establishes a framework for measuring fair value under generally accepted accounting principles and expands disclosures about fair value measurement. Under the standard, fair value refers to the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the market in which the reporting entity transacts. It clarifies the principle that fair value should be based on the assumptions market participants would use when pricing the asset or liability. In support of this principle, the standard establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. Under the standard, fair value measurements would be separately disclosed by level within the fair value hierarchy. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007. The Company adopted SFAS 157 effective January

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Notes to Consolidated Financial Statements

1, 2008. Adoption of this statement did not have a material impact on the Company's financial condition, results of operations and cash flows.

In February 2007, the FASB issued SFAS No. 159 "The Fair Value Option for Financial Assets and Financial Liabilities — as amended ("SFAS 159"). SFAS 159 permits entities to elect to report eligible financial instruments at fair value subject to conditions stated in the pronouncement including adoption of SFAS 157 discussed above. The purpose of SFAS 159 is to improve financial reporting by mitigating volatility in earnings related to current reporting requirements. The Company considered the applicability of SFAS 159 and determined not to adopt it at this time.

3. Related Party Transactions

On September 17, 2007, the Company entered into a drilling program with 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"). Under the terms of the Ten Well Program, Hoactzin was to pay the Company $400,000 for each well in the Ten Well Program completed as a producing well and $250,000 per drilled 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% of working interest revenues 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. The Company accounted for funds received for interests in the Ten Well Program as an offset to oil and gas properties and no gain or loss was recognized from these transactions.

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 90 barrels per day in total. Hoactzin paid a total of $3,850,000 (the "Purchase Price") for its interest in the Ten Well Program resulting in the Payout Point being determined as $5,215,595. 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 well, 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 in approximately four years solely from the oil revenues from the wells. However, under the terms of the Company's agreement with Hoactzin reaching the Payout Point has been accelerated by operation of a second agreement by which Hoactzin will apply 75% of the net proceeds it receives from

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a methane extraction project discussed below being developed by the Company’s wholly-owned subsidiary, Manufactured Methane Corporation, (“MMC”) to the Payout Point. Those methane project proceeds when applied should result in the Payout Point being achieved sooner than the estimated four year period based solely upon revenues from the Program wells.

On September 17, 2007, Hoactzin, simultaneously with subscribing to participate in the Ten Well Program, pursuant to an additional agreement with the Company was conveyed a 75% net profits interest in the methane extraction project being developed by “MMC” at the Carter Valley landfill owned and operated by BFI Waste Systems of Tennessee, LLC in Church Hill, Tennessee (the "Methane Project"). When the Methane Project comes online, the revenues from the Project received by Hoactzin will 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 Ten Well Program or 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 an additional 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. At the time the agreement was negotiated, the Company's forecast of the probable results of the projects indicated that there was little risk that the option to acquire preferred stock would ever arise, so the Company placed no significant value to the preferred stock option. By December 31, 2008 the amount of net revenues received by Hoactzin from the Ten WellProgram has reduced its obligation for the amount of the funds it had advanced for the Purchase Price from $3,850,000 to $1,950,165. The conversion option would be set at issuance of the preferred stock at the then twenty business day trailing average closing price of Company stock on the American Stock Exchange. Hoactzin has a similar option each year after 2009 in which Hoactzin’s then-unrecovered Purchase Price at the beginning of the year is not reduced 20% further by the end of that year, using the same conversion option calculation at date of the subsequent year’s issuance if any. The Company, however, may in any year make a cash payment from any source in the amount required to prevent such an exchange option for preferred stock from arising. In addition, the conversion right is limited to no more than 19% of the outstanding common shares of the Company. In the event Hoactzin’s 75% net profits interest in the Methane Project were fully exchanged for preferred stock, by definition the reduction of that 75% interest to a 7.5% net profits interest that was agreed to occur upon the receipt of 1.3547 of the Purchase Price by Hoactzin could not happen because the larger percentage interest then exchanged, no longer exists to be reduced. Accordingly,

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Hoactzin would retain no net profits interest in the Methane Project after a full exchange of Hoactzin's 75% net profits interest for preferred stock.

Under this exchange agreement, if no proceeds at all were received by Hoactzin through 2009 or in any year thereafter (i.e. a worst-case scenario already impossible in view of the success of the Program), then Hoactzin would have an option to exchange 20% of its interest in the Methane Project in 2010 and each year thereafter for preferred stock with liquidation value of 100% of the Purchase Price (not 135%) convertible at the trailing average price before each year's issuance of the preferred stock. The maximum number of common shares into which all such preferred stock could be converted cannot be calculated given the formulaic determination of conversion price based on future stock price.

However, revenues from the Ten Well Program have already resulted in 25% of the Purchase Price having already been reached. Accordingly, it is not likely that any requirement to issue preferred stock will arise in 2010 or any succeeding years.

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 interests 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 has 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 has 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 work-over activities undertaken on Hoactzin's managed properties during the term of the Management Agreement. The term of the Management Agreement is the earlier of the date Hoactzin sells its interests in its managed properties or five years.

4. Deferred Conveyance/Prepaid Revenues

The Company has adopted a deferred conveyance/prepaid revenues presentation of the transaction 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. This deferred conveyance presentation for the year 2008 will be compared to adjusted year-end 2007 figures for the purposes of this comparison.

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As part of the deferred conveyance presentation, the Company has allocated $853,000 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 $2,997,000 and the prepaid revenues were $853,000.

The Company has established a separate deferred conveyance and a prepaid revenue account 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 distrubuted 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. All releases for periods through December 31, 2008 are to the Ten Well Program as the Methane Project was not scheduled to go online until late in 2008 and gas revenues would first be received in 2009. The prepaid revenues will be released using the units of production method when the Methane Project comes online in 2009.

The impact of the Hoactzin Agreement through December 31, 2008 is as follows. Of the $3,850,000 Purchase Price invested by Hoactzin in September 2007, a total of $120,058 was paid to Hoactzin by December 31, 2007 attributable to the production of 1,403 barrels of oil in 2007 attributable to Hoactzin’s interest. All proceeds paid to Hoactzin in 2008 were from Hoactzin’s interest in the Ten Well Program oil wells. The volume that is attributable to Hoactzin’s interest is 19,438 barrels for the yearly production through December 31, 2008 for a total of $1,779,777 in 2008.The reserve information for the parties’ respective Ten Well Program interests during calendar year 2008 are indicated in the table below. These calculations were made using the 2008 year-end price of $34.04 per barrel, as required by SEC regulations.It should be noted that the table reflects only the reserve valuations based on the fact that in 2008 only the Program wells were contributing to reaching the point when the Company receives a larger portion of the production, sometimes referred to as the “flip point.” Hoactzin paid a total Purchase Price of $3,850,000 for its interest in the Ten Well Program resulting in the Payout Point or “flip point” being determined as $5,215,595. In fact, when the Methane Project contributes to the Payout Point being reached, this will accelerate that Payout Point being reached. Thus the Company’s reserves attributable to its interests will increase from those listed in this table because of the contribution made by Methane Project proceeds toward reaching the Payout Point when the Company’s interest in production increases.   This fact does not consider the additional but separate effect of price changes for both oil and for gas, which will also affect the annual determination of reserve values.

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Reserve Information for Ten Well Program Interests

For Year Ended December 31, 2008

	Barrels Attributable to Party's Interest	Future Cash Flows Attributable to Party's Interest	Present Value of Future Cash Flows Attributable to Party's Interest
Tengasco, Inc.	64,360	$1,953,574	$1,071,601
Hoactzin Partners, L.P	128,270	$3,079,780	$2,030,880

As of year-end 2008 the original invested amount of $3,850,000 has been reduced by 50% to $1,950,165. This amount is the total of the deferred conveyance of $1,097,165 and the prepaid revenue account of $853,000. Hoactzin's first right to convert its invested amount of $3,850,000 into preferred stock is only exercisable to the extent Hoactzin's investment has not been reduced by 25% by the end of 2009. Consequently, under the exchange agreement, Hoactzin is already precluded by these results from any possibility of exercising its contingent option to convert into preferred stock until the year ending December 31, 2011 at the earliest. All of the $1,899,835 paid from the program has been from the Ten Well Program and the deferred conveyance account has been reduced from $2,997,000 to $1,097,165.

Hoactzin has a similar option each year after 2010 in which Hoactzin's then-unrecovered invested amount at the beginning of the year 2011 is not reduced 20% further by the end of that year. As noted, in future periods, the Company anticipates that

this Hoactzin investment will continue to be further reduced by sales of oil produced from the Ten Well Program, or methane produced from the Methane Project, or both. From inception of the project through December 31, 2009, the Company projects that the original $3.85 million Purchase Price will be reduced by 76% to $924,000. For the year ending December 31, 2010, the amount is projected to be reduced to $0. As a result, Hoactzin's contingent option to exchange for preferred stock would fully terminate without any further annual reduction tests. These projections are based upon expected production levels from the oil wells in the Ten Well Program and an estimated 400 Mcf/day production from the Methane Project using $40 oil prices and a $5 per Mcf gas sales price net of operating expenses. The projection will vary with the actual oil and gas prices, production volumes, and expenses experienced in 2009 and 2010. Based on these projections the Company considers that it is a remote contingency that any right of Hoactzin to elect to exchange its Methane Project interest for Company preferred stock will ever arise. However, in the event of a conversion of Hoactzin's Methane Project interest for Company preferred stock as set out in limited circumstances in the applicable agreement, and which the Company anticipates is highly unlikely, there would be a debit to the deferred conveyance liability and the prepaid revenue account for both the Ten Well Program and Methane Project because no contingent option would remain on such a conversion, and the Company would simultaneously credit preferred stock in the

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converted amount. In the event of the termination of the option to convert into preferred stock because the $3.85 million has been repaid from the Ten Well Program or Methane Project or both, the applicable oil and gas properties will be deemed to have been fully conveyed to Hoactzin and the Ten Well Program account, will be credited and the liability will be removed, as at this time the price received for the program will be fixed and determinable. Under this circumstance, the prepaid revenue account would continue to be released under the units of production method.

5. Oil and Gas Properties

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

December 31,	**2008**	**2007**
Oil and gas properties, at cost	**$23,030,870**	**$22,586,429**
Unevaluated properties	**1,242,566**	**3,110,768**
Accumulated depreciation, depletion and amortization	**(10,131,738)**	**(8,757,654)**
Oil and gas properties, net	**$14,141,698**	**$16,939,543**

During the years ended December 31, 2008, 2007, and 2006 the Company recorded depletion expense of $1,374,084, $834,638 and $1,144,711 in 2006.

6. Pipeline Facilities

In 1996, the Company began construction of a 65-mile gas pipeline (1) connecting the Swan Creek development project to a gas purchaser and (2) enabling the Company to develop gas transportation business opportunities in the future. Phase I, a 30-mile portion of the pipeline, was completed in 1998. Phase II of the pipeline, the remaining 35 miles, was completed in March 2001. The estimated useful life of the pipeline for depreciation purposes is 30 years. The Company recorded $544,000, $544,000 and $544,000, in depreciation expense related to the pipeline for the years ended December 31, 2008, 2007 and 2006, respectively.

In January 1997, the Company entered into an agreement with the Tennessee Valley Authority ("TVA") whereby the TVA allows the Company to bury the pipeline within the TVA's transmission line rights-of-way. In return for this right, the Company paid $35,000 and agreed to annual payments of approximately $6,200 for 20 years.

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7. Other Property and Equipment

Other property and equipment consisted of the following:

December 31	*Depreciable Life*	**2008**	**2007**
Machinery and equipment	5-7 yrs	$ 830,734	$ 830,734
Vehicles	2-5 yrs	556,189	487,176
Other	5 yrs	63,734	63,734
Total		1,450,657	1,381,644
Less accumulated depreciation		(1,165,582)	(1,125,586)
Other property and equipment - net		$ 285,075	$ 256,058

The Company uses the straight-line method of depreciation ranging from two years to seven years, depending on the asset life.

8. Long Term Debt

Long-term debt to unrelated entities consisted of the following:

December 31,	**2008**	**2007**
Note payable to a financial institution, with interest payment only until maturity. (See Notes 15 & 16)	**$9,900,000**	**$4,200,000**
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 $24,000 due through 2011.	**226,900**	**173,660**

Total long-term debt	**10,126,900**	**4,373,660**
Less current maturities	**(74,877)**	**(57,887)**
Long-term debt, less current maturities	**$10,052,023**	**$4,315,773**

9. Commitments and Contingencies

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

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Office rent expense for each of the three years ended December 31, 2008, 2007 and 2006 was $63,346 respectively.

10. Black Diamond Purchase

Effective as of July 1, 2008, the Company purchased from Black Diamond Oil, Inc. an expected 80 barrels per day of oil producing properties and related leases in Rooks County, Kansas for $5.35 million. The Company also acquired producing oil wells and saltwater disposal wells, equipment, and the underlying working interests in leases comprising what is known as the Riffe field that had been owned by Black Diamond for many years. The purchase price was paid primarily from borrowings under its credit facility with Sovereign Bank and from company cash on hand. Following the purchase, the Company has borrowed a total of $9.9 million under its credit facility.

11. Asset Retirement Obligation

The Company follows the requirements of SFAS 143. Among other things, SFAS 143 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. Additionally, SFAS 143 required that upon initial application of these standards, the Company must recognize a cumulative effect of a change in accounting principle corresponding to the accumulated accretion and depletion expense that would have been recognized had this standard been applied at the time the long-lived assets were acquired or constructed. 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%, an estimated useful life of wells ranging from 30-40 years, estimated plugging and abandonment cost range from $5,000 per well to $10,000 per well. Management continues to periodically evaluate the appropriateness of these assumptions.

The following is a roll-forward of activity impacting the asset retirement obligation for the year ended December 31, 2008:

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Balance, December 31, 2006	$ 512,015
Accretion expense	70,929
Liabilities Settled	(51,843)
Balance, December 31, 2007	531,101
Accretion expense	155,006
Liabilities Settled	(30,380)
Balance, December 31, 2008	$ 655,727

12. Stock Options

In October 2000, the Company approved a Stock Incentive Plan. The Plan is effective for a ten-year period commencing on October 25, 2000 and ending on October 24, 2010. The aggregate number of shares of Common Stock as to which options and Stock Appreciation Rights may be granted to participants under the plan shall not exceed 7,000,000. 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.

Stock option activity in 2008, 2007 and 2006 is summarized below:

2008			*2007*		*2006*	
	Shares	*Weighted Average Exercise Price*	*Shares*	*Weighted Average Exercise Price*	*Shares*	*Weighted Average Exercise Price*
Outstanding, beginning of year				**$ .31**	2,584,000	$ .29
	2,441,000	**.30**	**2,596,000**			
Granted	**500,000**	**.74**	**-**	**-**	350,000	.60

Exercised	**(10,000)**	**.27**	**(126,000)**	**.42**		(338,000)	.42	
Expired/ canceled			**(29,000)**	**.64**		-	-	
Outstanding and exercisable, end of year	**2,931,000**	**.38**	**2,441,000**	**$**	**.30**	2,596,000	$	.31

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The following table summarizes information about stock options outstanding and exercisable at December 31, 2008:

	Options Outstanding		*Options Exercisable*
Weighted Average Exercise Price	*Shares*	*Weighted Average Remaining Contractual Life (years)*	*Shares*
$ 0.27	2,241,000	1.33	1,794,000
$ 0.58	110,000	2.05	110,000
$ 0.81	80,000	2.93	80,000
$ 0.57	400,000	5.08	160,000
$ 1.44	100,000	5.58	100,000

The weighted average fair value per share of options granted during 2006 and 2008 range from $0.15 to $1.06, calculated using the Black-Scholes Option-Pricing model. No options were granted in 2007.

Compensation expense of $128,187 related to stock options were recognized in 2006 and $100,877 in 2007 and $212,827 in 2008.

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 the following weighted average assumptions for 2006 and 2008: expected volatility of 100% for 2008 and 60% for 2006, a risk free interest rate of 3.67% in 2006 and 2008; and an expected option life remaining from 2.5 to 5 years for 2006 and 2008.

13. Income Taxes

The Company has taxable income for the periods ending December 31, 2008, December 31, 2007 and December 31, 2006.

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:

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December 31,	**2008**	**2007**	2006
Statutory rate	**34%**	**34%**	34%
Tax (benefit)/expense at statutory rate	**$2,323,000**	**$ 480,000**	$ 728,000
State income tax (benefit)/expense	**197,000**	**140,000**	85,000
Impairment write-down not deductible for tax purposes	**3,947,000**	**-**	-
Excess tax depreciation	**(65,000)**	**(85,000)**	(102,000)
Other	**(132,005)**	**3,000**	3,000
Utilization of NOL carry-forward	**(1,623,995)**	**(538,000)**	(714,000)
Net change in deferred tax asset valuation allowance	**(7,000,880)**	**(2,100,000)**	-
Total income tax provision (benefit)	**(7,000,880)**	**(2,100,000)**	-

The Company's deferred tax assets and liabilities are as follows:

December 31	**2008**	2007	2006
Deferred tax assets:			
Net operating loss carry-forward	**$6,015,000**	$7,314,000	$ 8,700,000
Capital loss carry forward	**263,000**	263,000	263,000
Excess of tax over book basis of oil and gas properties	**3,946,855**	-	-

Total deferred tax assets	**10,224,855**	7,577,000	8,963,000
Deferred tax liability:			
Basis difference in pipeline	**1,123,975**	1,208,975	1,310,975
Total deferred liability	**1,123,975**	1,208,975	1,310,975
Total net deferred taxes	**9,100,880**	6,368,025	7,652,025
Valuation allowance	**-**	(4,268,025)	(7,652,025)
Net deferred tax asset	**$9,100,880**	$2,100,000	**-**

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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. The Company has had recurring taxable income for its last three fiscal years. As of January 1, 2008, the Company had available approximately $21,000,000 of net operating loss carry forwards to offset future taxable income. During the year ended December 31, 2008, Management, using the “more likely than not” criteria for recognition, determined that it would be likely to realize the benefit of all of its net operating loss carry forwards and accordingly recognized a deferred tax benefit of approximately $7 million. Deferred tax assets related to our net operating loss carryforwards are being reduced as they are applied against future taxable income with $1,623,995 of the tax benefit being utilized in 2008.

At December 31, 2008, deferred tax assets are $9,100,880. The Company recorded an additional $3,947,000 in deferred tax benefit as a result of the $11,608,397 write-down. The recognition of the deferred tax asset in 2008 will provide a better matching of income tax expense with taxable income in future periods.

No income tax expense was recognized for the years ended December 31, 2007 or December 31, 2006 because deferred tax benefits, derived from the Company’s prior net operating losses, were previously fully reserved and were being offset against tax liabilities that would otherwise arise from the results of current operations.

As of December 31, 2008, the Company had net operating loss carry-forwards of approximately $ 15.6 million which will expire between 2011 and 2023 if not utilized.

14. Supplemental Cash Flow Information

The Company paid approximately $447,336, $262,268, and $126,250, for interest in 2008, 2007 and 2006, respectively. No interest was capitalized in 2008, 2007 or 2006.

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15. Litigation Settlement

On May 10, 2004 the Court entered its final order approving the fairness of the settlement to the class, dismissing the action pursuant to a Settlement Stipulation, and fully releasing the claims of the class members in *Paul Miller v. M. E. Ratliff and Tengasco, Inc.,* No. 3:02-CV-644 in the United States District Court for the Eastern District of Tennessee, Knoxville, Tennessee. This action sought certification of a class action to recover on behalf of a class of all persons who purchased shares of the Company's common stock between August 1, 2001 and April 23, 2002, unspecified damages allegedly caused by violations of the federal securities laws. In January, 2004 all parties reached a settlement subject to court approval. The Court entered its order approving the settlement on May 10, 2004. Under the settlement, the Company paid into a settlement fund the amount of $37,500 to include all costs of administration, contributed 150,000 shares of stock of Miller Petroleum, Inc. owned by the Company and issued 300,000 warrants to purchase a share of the Company's common stock for a period of three years from date of issue at $1 per share subject to adjustments. The Rights Offering adjusted this price to $0.45 per share. These Warrants expired on September 12, 2008. The Miller Petroleum, Inc. investment had a net carrying value of $60,000 and a cumulative other comprehensive loss of $90,000, which was reversed from cumulative other comprehensive loss and recognized as a realized loss during the third quarter of 2004.

16. Bank Loan

On June 29, 2006 the Company closed a $50,000,000 revolving senior credit facility between the Company and Citibank Texas, N.A. in its own capacity and also as agent for other banks.

Under the facility, loans and letters of credit will be available to the Company on a revolving basis in an amount outstanding not to exceed the lesser of $50,000,000 or the borrowing base in effect from time to time. The Company's initial borrowing base was set at $2,600,000. The initial loan under the facility with Citibank closed on June 29, 2006 in the principal amount of $2.6 million, bearing interest at a floating rate equal to LIBOR plus 2.5%, resulting in an initial rate of interest of approximately 8.2%.

Interest only is payable during the term of the loan and the principal balance of the loan is due thirty-six months from closing. The facility is secured by a lien on substantially all of the Company's producing and non-producing oil and gas properties and pipeline assets. The facility has standard loan covenants such as current ratios, interest coverage ratios etc, with which the Company is in compliance. $1.393 million of the $2.6 million loan proceeds borrowed on June 29, 2006 were used by the Company to exercise its option to repurchase from Hoactzin Partners, L.P., the Company's obligation to drill the final six wells in the Company's 12-well Kansas drilling program for Hoactzin. The Company incurred loan closing costs consisting of legal fees, mortgage taxes, commissions and bank fees totaling $285,224. This amount will be amortized over the term of the note and its successor (See Note 17).

On April 19, 2007 the Company borrowed an additional sum of $700,000 from Citibank, N.A. under its existing revolving credit facility. The additional borrowing resulted from an increase in the Company's borrowing base under the Citibank credit facility from $2.6 million to $3.3 million based upon Citibank's periodic review of the Company's borrowing base. With the additional borrowing, the Company has borrowed the full amount of its $3.3 million borrowing base under the revolving Citibank credit facility. This loan was replaced with the Sovereign Bank loan on December 17, 2007.

17. Sovereign Bank

On December 17, 2007, Citibank assigned the Company's revolving credit facility with Citibank to Sovereign Bank of Dallas, Texas ("Sovereign") as requested by the Company. Under the facility as assigned to Sovereign, loans and letters of credit are available to the Company on a revolving basis in an amount outstanding not to exceed the lesser of $20 million or the Company's borrowing base in effect from time to time. The Sovereign 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 Company's initial borrowing base with Sovereign was set at $7.0 million, an increase from its borrowing base of $3.3 million with Citibank prior to the assignment.

On June 2, 2008, the Company entered into an amendment to its credit facility with Sovereign whereby the Company's borrowing base was raised by the Bank as a result of its review of the Company's currently owned producing properties. The borrowing base was raised to $11 million effective June 2, 2008. The Company has previously utilized about $4.2 million of the facility, leaving approximately $6.8 million available for use by the Company upon this borrowing base increase. The Company used $5.35 million of the then available $6.8 million for the purchase of the Riffe Field properties in Kansas. The total borrowing by the Company under the facility at year end 2008 and as of the date of this Report is $9.9 million.

On February 5, 2009 the Company amended its credit facility with Sovereign to provide for a monthly reduction of the Bank's commitment by $150,000 per month for the five month period of February through June of 2009. This commitment reduction is not a cash payment obligation of the Company but has the effect of reducing the Company's available borrowing base in monthly increments of $150,000 so that by June 2009 the Company's available borrowing base under the Sovereign facility will be reduced by $750,000 from $11.0 million to $10.25 million. The Company's borrowing base will be redetermined at the next regularly scheduled borrowing base review on June 15, 2009. At that time, the borrowing base is subject to be redetermined according to the parameters established by Sovereign and applied to all of its borrowers.

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(18) **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 Agreement was thereafter assigned to the Company's wholly-owned subsidiary, Manufactured Methane Corporation ("MMC"), and provides that MMC will purchase all the naturally produced gas stream presently being collected and flared at the municipal solid waste landfill in Carter Valley serving the metropolitan area of Kingsport, Tennessee that is owned and operated by Republic in Church Hill, Tennessee. Republic's facility is located about two miles from the Company's existing pipeline serving Eastman Chemical Company ("Eastman"). The Company has 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 gas stream by volume. The Company has constructed a small diameter pipeline to deliver the extracted methane gas to the Company's existing pipeline for delivery to Eastman (the "Methane Project").

The total cost for the Methane Project including pipeline construction, was approximately $4.3 million including costs for compression and interstage controls. 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) $825,000 of the funds the Company borrowed from its credit facility with Sovereign Bank. Commercial deliveries of gas will begin when the equipment is fully tested and emission permits are obtained. Upon commencement of operations, it is anticipated that the methane gas produced by the project facilities will be mixed in the Company's pipeline and delivered and sold to Eastman under the terms of the Company's existing natural gas purchase and sale agreement with Eastman. At current gas production rates and expected extraction efficiencies, when commercial operations of the Project begin, the Company initially estimated it would deliver about 418 MCF per day of additional gas to Eastman, which would substantially increase the current volumes of natural gas being delivered to Eastman by the Company from its Swan Creek field. The gas supply from this project 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, currently estimated by Republic to occur between the years 2022 and 2026.

As part of the Methane Project agreement, the Company agreed to install a new force-main water drainage line for Republic, the landfill owner, in the same two-mile pipeline trench as the gas pipeline needed for the project, reducing overall costs and avoiding environmental effects to private landowners resulting from multiple installations of pipeline. Republic has paid the additional material costs for including the water line of approximately $700,000. Construction of the gas pipeline needed to connect the facility with the Company's

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existing natural gas pipeline began in January 2008 and was completed in December 2008. As a certificated utility, the Company's pipeline subsidiary, TPC, required no additional permits for the gas pipeline construction.

At year-end 2008, MMC was finalizing steps necessary to declare the startup of commercial gas production at the Carter Valley landfill in Church Hill, Tennessee. Initial volumes of methane were produced in late December 2008 and have occurred on an intermittent basis since that time as MMC implemented the startup process. During the first two months of 2009, Eastman Chemical was reviewing its current air quality permits with regard to MMC's methane production and deliveries were suspended during that review. Eastman Chemical has now indicated to MMC in early March 2009 that it is prepared to commence taking delivery of the methane gas from MMC's Carter Valley facility. Accordingly, MMC expects to declare startup of commercial operations no later than the end of March 2009. Thereafter, MMC, Eastman Chemical, and Republic Services intend to schedule a formal grand opening of this facility in the spring of 2009.

Prior to declaring startup of commercial operations, MMC continues to fully integrate the gas supply from the landfill with the operations of the methane extraction equipment to maximize quality and quantity of the gas produced and to enable continuous daily production from the facility. The Company believes that this process is complete as of the date of this Report. To date, MMC has produced approximately 800 thousand cubic feet of methane gas that was extracted from the landfill gas. The produced methane was mixed with the natural gas produced from the Company's Swan Creek field and delivered to Eastman through the new 2.5 mile pipeline built from the landfill to connect with the Company's existing 65-mile natural gas pipeline.

The methane gas produced to date is of the high quality levels and heating content that MMC expected with the system design. MMC expects to be able to continuously produce and sell about 500 MCF per day, which significantly exceeds the original estimate of about 418 MCF per day that was made at the beginning of this project. This has happened because the landfill has grown during the time the Project has been in planning and construction, and the landfill owner Republic has improved both the quality and volume of gas collected by the gas gathering system in the landfill itself.

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On September 17, 2007, Hoactzin, simultaneously with subscribing to participate in the Ten Well Program (the "Program"), pursuant to a separate agreement with the Company was conveyed a 75% net profits interest in the Methane Project. When the Methane Project comes online, the revenues from the Project received by Hoactzin will 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 a 7.5% net profits interest. The Company believes that the application of revenues from the methane project to reach the Payout Point could accelerate reaching the Payout Point. As stated above, the Purchase Price paid by Hoactzin for its interest in the Program exceeded the Company's anticipated and actual costs of drilling the ten wells in the Program. Those excess funds provided by Hoactzin were used to pay for approximately $1,000,000 of equipment required for the Methane Project, or about 25% of the Project's capital costs. The availability of the funds provided by Hoactzin eliminated the need for the Company to borrow those funds, to have to pay interest to any lending institution making such loans or to dedicate Company revenues or revenues from the Methane Project to pay such debt service. Accordingly, the grant of a 7.5% interest in the Methane Project to Hoactzin was negotiated by the Company as a favorable element to the Company of the overall transaction.

19. 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.

20. Quarterly Data and Share Information (unaudited)

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

Fiscal Year Ended 2008

	First Quarter (b)	Second Quarter	Third Quarter	Fourth Quarter(a)
Revenues	**$3,305,720**	**$4,633,588**	**$5,067,106**	**$2,594,260**
Net loss/income	**5,812,011**	**1,421,707**	**1,562,967**	**(8,627,023)**
Net loss/income attributable to common stockholders	**5,812,011**	**1,421,707**	**1,562,967**	**(8,627,023)**
Income/loss per common share	**$ .10**	**$ 0.02**	**$ 0.03**	**$ (0.14)**

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Fiscal Year Ended 2007

	First Quarter	Second Quarter	Third Quarter (b)	Fourth Quarter (b)
Revenues	**$1,772,400**	**$2,220,439**	**$2,375,229**	**$3,000,556**
Net loss/income	**(209,165)**	**330,756**	**1,580,662**	**1,808,069**
Net loss/income attributable to common stockholders	**(209,165)**	**330,756**	**1,580,662**	**1,808,069**
Income/loss per common share	**$ 0.00**	**$ .01**	**$ 0.03**	**$ 0.03**

(a) This amount includes an $11,608,397 ceiling test write-down due to reduced oil prices in the year-end reserve report, after tax effect of $7,661,397.

(b)The company recorded $1.1 million in deferred tax asset in the third quarter of 2007 and $1.0 million in the fourth quarter of 2007, and $5,227,000 in the first quarter of 2008.

21. 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 reserve quantities, as well as future production and discounted cash flows before income taxes, were determined by LaRoche Petroleum Consultants Ltd. in 2008, 2007 and 2006.

Oil and Gas Related Costs

The following table sets forth information concerning costs related to the Company's oil and gas property acquisition, exploration and development activities in the United States during the years ended:

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	2008	2007	2006
Property acquisitions			
Proved	**$5,350,000**	**$200,000**	
Unproved			
Less –proceeds from			
Sales of properties	**-**	**-**	-
Development Cost	**6,614,414**	**4,990,611**	4,172,462
	$11,964,414	**$5,190,611**	$ 4,172,462

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 for the years ended December 31,	2008	2007	2006
Revenues	**$15,569,904**	**$9,300,144**	$ 8,896,036
Production costs and taxes	**(5,730,472)**	**(4,160,488)**	(3,145,244)
Depreciation, depletion and amortization	**(1,374,084)**	**(834,638)**	(1,144,711)
Income from oil and gas producing activities	**$ 8,465,348**	**$ 4,305,018**	$ 4,606,081

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.

Oil and Gas Reserves

The following table sets forth the Company's net proved oil and gas reserves at December 31, 2008, 2007 and 2006 and the changes in net proved oil and gas reserves for the years then ended. Proved reserves represent the quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in the future years from known reservoirs under existing economic and operating conditions. Reserves are measured in barrels (bbls) in the case of oil, and units of one thousand cubic feet (Mcf) in the case of gas.

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	Oil (bbls)	*Gas (Mcf)*
Proved reserves at December 31, 2005	1,374,463	4,763,239
Revisions of previous estimates	20,120	(3,318,074)
Improved recovery	110,460	-
Purchase of Reserves in Place		
Extensions and Discoveries	396,152	-
Production	(189,189)	(138,078)
Sales of Reserves in Place	-	-
Proved reserves at December 31, 2006	1,712,006	1,307,087
Revisions of previous estimates	699,578	(45,948)
Improved recovery	19,502	-
Purchase of Reserves in Place	16,234	
Extensions and Discoveries	13,838	-
Production	(185,188)	(126,746)
Sales of Reserves in Place	-	-
Proved reserves at December 31, 2007	2,275,970	1,134,393
Revisions of previous estimates	(1,312,999)	(120,186)
Improved recovery	58,814	-
Purchase of Reserves in Place	234,320	-
Extensions and Discoveries	153,992	-
Production (gross BBLS 237,994)		
Net to Tengasco	(162,431)	(104,043)
Sales of Reserves in Place	-	-
Proved reserves at December 31, 2008	1,247,666	910,164
Proved developed producing reserves at	1,239,940	907,302

resere
December 31, 2008

Proved developed producing reserves at	1,604,607	1,130,869
resere December 31, 2007		
	1,091,135	2,814,306
Proved developed producing reserves at	1,358,532	1,264,527
resere December 31, 2006		

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	Year Ended 12/31/08			**Year Ended 12/31/07**			**Year Ended 12/31/06**		
(amounts in thousands)	**Oil**	**Gas**	**Total**	**Oil**	**Gas**	**Total**	**Oil**	**Gas**	**Total**
Total proved reserves year-end reserve report	9,177	1,116	10,293	$52,117	$1,510	$53,627	$24,099	$2,370	$26,469
Proved developed producing reserves (PDP)	9,020	1,114	10,134	$36,319	$1,485	$37,804	$19,335	$2,370	$21,705
% of PDP reserves to total proved reserves	87.7	10.8	98.5	67%	3%	70%	73%	9%	82%
Proved developed non-producing reserves	157	2	159	$441	$25	$466	$529	$0	$529
% of PDNP reserves to total proved reserves	1.5	-	1.5	1%	0%	1%	2%	0%	2%
Proved undeveloped reserves (PUD)	0	0	0	$15,357	$0	$15,357	$4,235	$0	$4,235
% of PUD reserves to total proved reserves	-	-	0	29%	0%	29%	16%	0%	16%

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 two tables:

(amounts in thousands)			
December 31,	**2008**	2007	2006
Future cash inflows	**$ 51,388**	$ 206,276	$ 107,291
Future production costs and taxes	**(36,491)**	(76,944)	(52,033)
Future development costs	**(309)**	(10,175)	(4,505)
Future income tax expenses	**-**	-	-
Net future cash flows	**14,588**	119,157	50,753
Discount at 10% for timing of cash flows	**(4,295)**	(65,530)	(24,284)

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Discounted future net cash flows from proved reserves	**$ 10,293**	$ 53,627	$ 26,469

(amounts in thousands)

	2008	2007	2006
Balance, beginning of year	**$ 53,627**	$ 26,469	$ 37,179
Sales, net of production costs and taxes	**(9,839)**	(5,140)	(5,751)
Discoveries and extensions	**1,492**	1,166	1,734
Purchases of Reserves	**1,642**	568	-
Changes in prices and production costs	**(30,890)**	16,893	(6,329)
Revisions of quantity estimates	**(9,373)**	16,584	(1,781)
Sale of Reserves	**-**	-	-
Interest factor - accretion of discount	**1,029**	2,647	3,718
Net change in income taxes	**-**	-	-
Changes in future development costs	**3,251**	(5,669)	(3,010)
Changes in production rates and other	**(646)**	109	709
Balance, end of year	**$ 10,293**	$ 53,627	$ 26,469

Estimated future net cash flows represent an estimate of future net revenues from the production of proved reserves using current sales prices, along with estimates of the operating costs, production taxes and future development and abandonment costs (less salvage value) necessary to produce such reserves. The average prices for December 31, 2008, 2007, and 2006 were $33.96, $85.44, and $56.50, per barrel of oil and $7.76, $7.21, and $8.33 per MCF of gas, respectively. No deduction has been made for depreciation, depletion or any indirect costs such as general corporate overhead or interest expense.

Operating costs and production taxes are estimated based on current costs with respect to producing properties. Future development costs are based on the best estimate of such costs assuming current economic and operating conditions.

Income tax expense is computed based on applying the appropriate statutory tax rate to the excess of future cash inflows less future production and development costs over the current tax basis of the properties involved, less applicable net operating loss carry-forwards, for both regular and alternative minimum tax. For the years ended December 31, 2008, 2007 and 2006 the Company's available net operating loss carry forwards offset all tax effects applicable to the discounted future net cash flows.

The future net revenue information assumes no escalation of costs or prices, except for gas sales made under terms of contracts which include fixed and determinable escalation.

Future costs and prices could significantly vary from current amounts and, accordingly, revisions in the future could be significant.

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Under current SEC rules, the Company's proved reserves are measured by what can be described as a "snapshot" analysis based on commodity prices of oil and gas on the last day of each calendar year. This method has been recognized as having limitations, and accordingly the SEC has adopted new reserve reporting rules beginning in 2009. However, the effects of this snapshot analysis in 2008 on the Company have caused the Company's reserve volumes and values to drop for two reasons. First, there is the magnified effect of single day snapshot pricing on the Company's "proved, developed producing" reserves, referred to as the PDP reserve category. Although 2008 also saw record high oil prices for crude oil, the pricing used under SEC rules for 2008 reserve reporting purposes is the December 31, 2008 price of $34.04 per barrel which is approximately 20% of prices received for the Company's production in mid-2008 and the lowest oil price in recent memory. Consequently, under the snapshot analysis, the lower 2008 end-of-year price has effectively caused the long-lived total values of our PDP reserves to be reduced by the discounted cash flow analysis of the future revenues from each of our wells. In 2007, the Company's PDP reserves were 2,275,970 barrels of oil and were valued at $38 million using the 2007 year-end snapshot price of $85.41 per barrel discounted to present value at 10%. In 2008, despite the addition of interests in 12 new wells and with all of the same 2007 producing properties, the reserve number fell, because of the 2008 year-end snapshot price of $34.04 per barrel resulting in the reserves being determined to be 1,240,000 barrels of PDP valued at $10.134 million. Oil wells with lower volumes, long lives, and low production decline rates (like most of our older Kansas wells) are subject to falling out of the reserve valuation methodology many years before they are likely to stop actual production if depressed oil prices are used as the basis for calculations. This occurs at a point in time when future expenses of these low volume wells, which are not reduced for operating low volume wells, meet or exceed the depressed snapshot price for the produced oil, which price is not allowed to escalate. From that point in time onward the well is assumed for valuation purposes to be shut-in or abandoned because it is assumed it would be unprofitable to operate. The consequence of this methodology is that for all outlying years where actual production is physically possible at a reasonable price, production volumes from those outlying years are removed from the PDP reserve valuation altogether, and are not discounted to a present value for 2008 reserve valuation purposes.

Secondly, the snapshot method also provides another challenge to maintaining the values of "proved undeveloped" ("PUD") reserves. In order to include reserves associated with future drilling on PUD locations, it is necessary to demonstrate that a company has the financial ability to actually drill those locations. Said another way, if a location appears to be likely to produce hydrocarbons, it cannot be included in reserves as PUD if a given company has no way to actually pay for drilling the well to obtain production. Using a lower snapshot price of oil, such as the 2008 year-end price, reduces cash flow so that it may become difficult or impossible to demonstrate that the Company has sufficient cash flow to drill these PUD locations and thereby be able to include the value of the reserves likely to be produced from these locations in the PUD category. In addition, future costs anticipated to be required to drill and operate a PUD location are not held to a fixed or current level and are not discounted for lower volumes, while the prices received for future production from such a well are held to the snapshot of the lower year-end price. In places such as Kansas, the

discounted reserve values, when based on any low snapshot price are made to appear even less capable of being able to recover drilling and operating costs as is necessary to include the well in the PUD category. In 2007, the Company had 39 PUD locations that contributed to the Company's reserve valuation in the amount of $15 million. During 2008, the Company added additional PUD locations to the reserves, and drilled some wells previously on the PUD list from 2007, moving these reserves into the PDP category. Also during 2008, the Company continued to build its PUD elements of value throughout the course of the year from the geologic and engineering points of view. Nevertheless, because of the much lower 2008 year-end price as compared to the 2007 year-end price, the Company was required to remove all the future PUD locations as they are now valued at $0 and the corresponding volumes that could be produced by drilling these future wells from the Company's reserve valuation. This happened because it appears unlikely that such wells would be drilled or have value if prices remain at the snapshot end of year 2008 price level for all future periods, as is assumed under current reserve reporting standards.

The Company will report its proved reserves under the new moderation roles enacted by the SEC for the year ending December 31, 2009. At year end 2009 it remains possible that if commodity prices are significantly higher (or lower) than the year-end snapshot price for 2008, the Company's 2009 reserve valuations may correspondingly increase (or decrease) significantly from the year end 2008 valuations, as a result of the same factors set out above. The Company eagerly awaits the rule changes adopted by the SEC for 2009 as management believes that the new reporting rules and standards will give a more accurate and realistic picture of the Company's future cash flow values and drilling opportunities both as to PDP and PUD categories of the Company's reserves as well as adding new reportable categories for probable and possible reserves.

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