TENGASCO INC
Form 10-K
March 31, 2008

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, 2007** 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	**87-0267438**
(State or other jurisdiction of incorporation or organization)	(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 o	Non-accelerated Filer o (Do not check if a Smaller Reporting Company)	Smaller Reporting Company x

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

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 29, 2007 closing price $0.65): **$24,375,566**

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 3, 2008): **59,155,750**

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, 2008, 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.

Table of Contents

Part I	**Table of Contents**	Page
	Item 1. Business	1
	Item 1A. Risk Factors	18
	Item 1B. Unresolved Staff Comments	27
	Item 2. Properties	27
	Item 3. Legal Proceedings	38
	Item 4. Submission of Matters to a Vote of Security Holders	38
Part II		
	Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	38
	Item 6. Selected Financial Data	40
	Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation	

		41
	Item 7A. Quantitative and Qualitative Disclosures About Market Risk	
		49
	Item 8. Financial Statements and Supplementary Data	
		50
	Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure	
		50
	Item 9A(T) Controls and Procedures	50
	Item 9B. Other Information	52
Part III		
	Item 10. Directors and Executive Officers and Corporate Governance	
		53
	Item 11. Executive Compensation	53
	Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	
		53
	Item 13. Certain Relationships and Related Transactions, and Director Independence	
		55
	Item 14. Principal Accountant Fees and Services	55
Part IV		
	Item 15. Exhibits, Financial Statement and Schedules	55
	SIGNATURES	58

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 also include statements regarding revenue, margins, expenses, and earnings analysis for 2007 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 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, producing and transporting 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.

In 1998, the Company acquired from AFG Energy, Inc. (“AFG”), a private company, approximately 32,000 acres of leases in the vicinity of Hays, Kansas (the “Kansas Properties”). Included in that acquisition were 273 wells, including 208 working wells, of which 149 were producing oil wells and 59 were producing gas wells, a related 50-mile pipeline and gathering system, three compressors and 11 vehicles. The Company sold the Kansas gas producing wells, gathering system and compressors effective February 1, 2005. During 2007, the Kansas Properties produced an average of 14,860 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 2007 the Company sold an average of 347 thousand cubic feet of natural gas per day and 573 barrels of oil per month from 21 producing gas wells and 5 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 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.

In December 2007 the Company entered into 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 and has begun investigating the economics of participation in oil and gas projects 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 149 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 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.

In 2007, the Company continued to focus its exploration and drilling activities in Kansas. In 2007, the Company drilled 16 new wells on its Kansas Properties, of which 9 wells were under the ten well program discussed below in greater detail. Of these new wells, 10 are producing commercial quantities of oil. These new wells are producing approximately 135 barrels of oil per day. The Company also continued in 2007 its program of work-overs of existing wells to increase production. The Company’s focus in 2007 on its Kansas oil production and the results achieved by the Company from its ongoing operations, drilling and work-overs are having a positive impact on the Company’s reserves resulting in the Company’s total proved reserves at December 31, 2007 having more than doubled in value from year-end 2006. Fifty-Six (56%) percent of that increase in reserve growth is attributable to the Company’s ongoing operational activities and the new Proved Undeveloped (PUD) future drilling locations that the Company has established as a result of these successes. See, Item 2, “Properties” – “Reserve Analysis” for a more detailed discussion of the Company’s reserves.

During 2007, the Company also continued its 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. The Company intends in 2008 to continue to acquire additional leases in the area of its existing wells.

A. <u>Kansas Drilling Programs</u>

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 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"). The Company intends to account for funds received for interests in the Program as an offset to oil and gas properties.

As of the date of this Report, the Company has drilled all ten wells in the Program. 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 for its interest in the 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 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 toward reaching the Payout Point. (The methane extraction project is discussed in greater detail below.) Those 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.

2. The Eight Well Program

In 2006, the Company drilled the last two wells of an eight-well drilling program in Kansas (the "Eight Well Program"). The Eight Well Program was offered to the holders of the Company's Series A 8% Cumulative Convertible Preferred Stock ("Series A Shares") 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. The Eight Well Program has produced sufficient revenues to the participants so that the management fee to the Company became due 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 to the Company's interest in those wells.

3. The Twelve Well Program

In October, 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.

In 2006, the Company drilled four wells in the Twelve Well Program bringing the total number of wells drilled in that Program to six. All but one of those wells is continuing to produce commercial quantities of oil.

On June 29th, 2006 the Company closed a $50,000,000 credit facility with Citibank Texas, N.A. The Company's initial borrowing base was set at $2,600,000 and the Company borrowed that amount on June 29, 2006 and used $1.393 million of the loan proceeds to exercise its option to repurchase from Hoactzin, the Company's 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. Consequently, all well-drilling obligations of the Company under both the Eight Well and Twelve Well Programs with former preferred stockholders as participants have been satisfied. 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 will now receive 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 was exercised.

B. Kansas Production

Gross oil production in 2007 was just slightly less than 2006 resulting from the loss of production in January 2007 due to an electricity outage caused by an ice storm. As a result of that storm, many counties in Kansas, including some counties where the Company has wells, lost power for the entire month of January. Producing wells in those counties were unable to produce without electricity to run the well pumps during the power outage. Consequently, in January 2007 the Company saw production and revenue decline from monthly levels in late 2006. None of the Company's producing wells were physically damaged by the ice storm or by non-production during the absence of power, but the storm did substantially adversely impact production levels and sales in the first two months of 2007 while at the same time causing an increase in expenses. Eventually new poles and lines were rebuilt on a locally massive scale and electrical power was restored, and the Company experienced a rebound of production commencing in March 2007. In 2007, the Company produced 178,311 barrels of oil in Kansas compared to 179,555 in 2006, a decrease of 1,244 barrels for the year. Additionally, the wells in the Eight Well Program reached the reversionary "flip point" in April 2007. This is the point at which the Company started receiving 85% of the participant's interest plus the Company's original interest of (19.6%) for an approximate total net interest to the Company equal to an 88% working interest. In 2007, the wells from the Eight Well Program produced 22,195 gross barrels of oil; the wells in the Twelve Well Program (now converted to a six well program) produced 15,864 gross barrels; wells that were polymered produced 19,502 barrels; and the two new wells drilled produced 2,566 gross barrels in 2007. The Ten Well Program had some limited production in 2007 as wells were being completed through the year-end. During 2007, the Ten Well Program produced 3,649 barrels from 5 wells that were completed by year-end. The five other wells in the Ten Well Program that were drilled in 2007 were completed in 2008. In March 2008 the tenth and final well from the Ten Well Program was drilled and completed as a producer. As of the date of this Report, nine of ten wells drilled in the Program have been completed as producers and are producing approximately 106 barrels per day. During the first half of 2008 the Company expects the reversionary flip point for the Twelve Well Program now converted to a six well program, to be achieved.

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. Management has made the decision to simultaneously undertake as many of these projects that can be paid from the Company's current cash flow as soon as the Company is able to obtain third party crews and equipment to perform the work. Workovers done to date on a limited scale have been successful in Kansas. The work-overs included a treatment of wells by injection of polymers (a type of plastic compound) that has sealed off almost all of the water from entering the combined oil/water fluid stream that is naturally produced from the wells, while at the same time increasing the total quantity of crude oil that is actually produced per day from the treated wells. Although there can be no assurances, similar work-overs when completed might reduce water production and its associated removal expense and increase oil production from several of the Company's other existing oil wells in Kansas.

2. <u>The Tennessee Properties</u>

Amoco Production Company, during the late 1970's and early 1980's acquired 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. In 1982, 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 concluded a legal action under state law and acquired the Swan Creek leases.

A. <u>Swan Creek Pipeline Facilities</u>

The Company completed Phase I of its pipeline from the Swan Creek Field, a 30-mile pipeline made of six and eight-inch steel pipe running from the Swan Creek Field into the main city gate of Rogersville, Tennessee in 1998. The cost of constructing Phase I of the pipeline was approximately $4,200,000. Construction of Phase II of the Company's pipeline system was completed in 2001. Phase II was an additional 35 miles of eight and 12-inch pipe laid at a cost of approximately $12.1 million, extending the Company's pipeline from a point near the terminus of Phase I and connecting to a meter station at Eastman Chemical Company's ("Eastman") plant in Kingsport, Tennessee. The completed pipeline system extends 65 miles from the Company's Swan Creek Field to Kingsport, Tennessee and was built for a total cost of $16,329,552.

B. <u>Swan Creek Production and Development</u>

Management obtained state regulatory approval in 2003 for drilling additional infield wells in the Swan Creek Field resulting in an increased density of wells. At that time, management expected that an increased density of wells within the existing Swan Creek Field would result in additional reserves in accordance with reservoir engineering standards.

Thereafter, the Company drilled and tested two new infield development wells in the Swan Creek Field. The results of these wells together with the accumulation of data from previously drilled wells and seismic data indicated 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. Consequently, the Company has not drilled any new wells in the Swan Creek Field since 2004.

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 21wells 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 2006 to 2007 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 2006-2007 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 2007, the Company's volume sold from the field was approximately 347 MMBtu per day. The Company's contracts with these customers are only 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 its industrial contracts if the volumes were physically available from the Field. However, in the event that the Company were 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 2007, the Company had 21 producing gas wells and 5 producing oil wells in the Swan Creek Field. Sales from the Swan Creek Field during 2007 averaged 347 Mcf per day compared to 378 Mcf per day in 2006.

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. 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 BFI in Church Hill, Tennessee. BFI's facility is located about two miles from the Company's existing pipeline serving Eastman Chemical Company ("Eastman"). Contingent upon obtaining suitable financing, the Company plans to acquire and install 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 plans to construct a small diameter pipeline to deliver the extracted methane gas to the Company's existing pipeline for delivery to Eastman (the "Methane Project").

MMC has placed equipment orders for its first stage of process equipment (cleanup and carbon dioxide removal) and the second stage of process equipment (nitrogen rejection) for the Methane Project. It is anticipated that the total costs for the Project including pipeline construction, will be approximately $4.1 million including costs for compression and interstage controls. The costs of the Methane Project to date have been 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 in the amount of approximately $1 million and (c) $825,000 of the funds the Company borrowed from its credit facility with Sovereign Bank. The Company anticipates that most of the remaining balance of the Methane Project costs will be paid from the Company's cash flow.

The Company anticipates that the equipment ordered by MMC will be manufactured and delivered to allow operations to begin in mid-2008 after equipment installation, testing, and startup procedures are begun. Commercial deliveries of gas will begin when the equipment is installed and tested, the pipeline is constructed and emission permits are obtained. Upon commencement of operations, the methane gas produced by the project facilities will be mixed in the Company's pipeline and delivered and sold to Eastman Chemical Company ("Eastman") under the terms of the Company's existing natural gas purchase and sale agreement. At current gas production rates and expected extraction efficiencies, when commercial operations of the Project begin, the Company would expect to deliver about 418 MMBtu 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. At an assumed sales price of gas of $7 per MMBtu, near the average natural gas price received by the Company in 2007, the anticipated net revenues would be approximately $800,000 per year from the Methane Project based on anticipated volumes and expenses. 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 BFI 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 BFI, 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. BFI will pay the additional costs for including the water line. Construction of the gas pipeline needed to connect the facility with the Company's existing natural gas pipeline began in January 2008. As a certificated utility, the Company's pipeline subsidiary, TPC, requires no additional permits for the gas pipeline construction. The Company currently anticipates that pipeline construction will be concluded approximately the same time as equipment deliveries and installations occur or in the May to June 2008 time period, subject to weather delays during wintertime construction.

On September 17, 2007, Hoactzin, simultaneously with subscribing to participate in the Ten Well 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 couldaccelerate reaching the Payout Point. As stated above, the 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.

Management Agreement with Hoactzin

On December 18, 2007, the Company entered into a Management Agreement with Hoactzin. On that same date, the Company also entered into an agreement with Charles Patrick McInturff employing him as a Vice-President of the Company. Pursuant to the Management Agreement with Hoactzin, Mr. McInturff's duties while he is employed as Vice-President of the Company will include the management on behalf of Hoactzin of its working 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. The term of the Management Agreement is the earlier of the date Hoactzin sells its interests in its managed properties or 5 years.

5. Other Areas of Development

The Company is seeking to purchase and has attempted to acquire additional existing oil and gas production in the Mid-Continent (USA) area. The Company is particularly interested in areas of Kansas, Oklahoma, and Texas. Although financing plans are uncertain, management believes that when a suitable property becomes available, a combination of such a property with our current reserves would allow the Company to create a financing mechanism that would make a purchase of the property possible. However, there is no assurance that a suitable property will become available or 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.

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 to the Coffeyville Resources Refining and Marketing, LLC (“Coffeyville Refining”) in Kansas City, Kansas. Coffeyville Refining is solely responsible for transportation 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 Industry

and Methods of Competition

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

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

13

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 on deposit.

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.

Number of Total Employees and Number of Full-Time Employees

The Company presently has twenty-seven full time employees and one part-time employee.

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 Knoxville, TN 37931	Chief Financial Officer	12/14/98

Business Experience[2]

Charles Patrick McInturff is 55 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

---

[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 2008 Annual Meeting of Stockholders.

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 to1986 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 will serve as Vice-President of the Company.

Cary V. Sorensen is 59 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 litigation department of Enron Corp. 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 49 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 athttp://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.

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 $26,645,810 as of December 31, 2007. 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 has been profitable in 2005, 2006, and 2007. However, 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 Credit Facility with Sovereign BankIs 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.

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, consistent with its customary natural gas and crude oil lending practices. Reductions in estimates of the Company’s natural gas and crude oil reserves could result in a reduction in the Company’s borrowing base, which would reduce the amount of financial resources available under the Company’s revolving credit facility to meet its capital requirements. Such a reduction could be the result of lower commodity prices or production, inability to drill or unfavorable drilling results, changes in natural gas and crude oil reserve engineering, the 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.

Declines In Oil or Gas Prices Will Materially Adversely Affect the Company's Revenues.

The Company's future financial condition and results of operations will 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. Prices for oil and natural gas are subject to fluctuations in response to relatively minor 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 and the overall economic environment. Although oil prices are currently at record high levels which has had a substantial favorable impact on the Company's revenues, there can be no assurances that prices will remain at the current rates or continue to increase as they have during the past year. A substantial or extended decline in oil or gas prices would have a material adverse effect on the Company's financial position, results of operations, quantities of oil and gas that may be economically produced, and access to capital. Oil and natural gas prices have historically been and are likely to continue to be volatile. This volatility makes it difficult to estimate with precision the value of producing properties in acquisitions and to budget and project the return on exploration and development projects involving the Company's oil and gas properties. In addition, unusually volatile prices often disrupt the market for oil and gas properties, as buyers and sellers have more difficulty agreeing on the purchase price of properties.

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 Company's Oil and Gas Operations Involve Substantial Costs and are

Subjectto 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.

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 as 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’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.

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 them to know conclusively prior to drilling a well whether oil or natural gas is present or may be produced economically.

The ultimate cost 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 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 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. The Company has not incurred ceiling limitation write-downs in the past. However, we cannot assure you that the Company will not experience ceiling limitation write-downs in the future.

Use of the Company’s Net Operating Loss Carryforwards may be limited.

At December 31, 2007, 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 appropropiate 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 writedowns or reversals, if they occur, may be material and substantially adverse.

The Company has Significant Costs to Conform to

Government Regulation of the Oil and Gas Industry.

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

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

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

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

Insurance Does Not Cover All Risks.

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’sMethane 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.

The Company is Not Competitive 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 OwnsA 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, 2007, 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 50,000 shares of common stock. His ownership and voting control over approximately 36% 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 3, 2008, the Company had 59,155,750 shares of common stock outstanding of which 21,654,879 shares were held by affiliates and, in addition, 2,841,000 shares of common stock were subject to outstanding options granted under the Tengasco, Inc. Stock Incentive Plan (of which 1,627,000 shares were vested at March 3, 2008).

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 capital raising 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

Not Applicable

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. The Company does not yet have production interest in Texas, but it is anticipated that an opportunity to participate in the properties the Company manages on behalf of Hoactzin Partners, L.P. will be available in the future.

Kansas Properties

The Kansas Properties as of December 31, 2007 contained 192 leases totaling 28,934 acres in the vicinity of Hays, Kansas. The increase in the total volume of acreage of the Company’s Kansas Properties from 27,837 acres at the end of 2006 is primarily due to the purchase of two producing leases, the Heyl and RJ Thyfault. The Company focused its drilling, development, and exploration activities in Kansas in 2007 on evaluation of older producing properties, and those properties acquired in 2005 and 2006. Many of these leases, however, 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%. 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.

Kansas as a whole is of major significance to the Company. The majority of the Company's current reserve value, current production, revenue, and future development objectives are centered in the Company's ongoing interests in Kansas. By using 3-D seismic evaluation on existing locations owned by the Company in Kansas, the Company has added and continues to add proven direct offset locations. As a result of recent higher commodity prices for its oil, the Company has been able to drill from cash flow and attract favorable drilling partner programs in which the Company retains not only a carried beginning interest but a higher-than-industry-standard reversionary interest. The Company expects to continue this mix of company drilling and program drilling depending primarily on future cash flow and future oil prices. 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, 2007:

- Kansas accounted for 91.4% of the Company's revenue (i.e. $8,560,097 of $9,368,624.)

- Kansas accounted for 86% of the Company's total production measured in BOE (Barrel of Oil Equivalent)

- Kansas contributes $14.791 million in value of future proven development locations as of year end 2007, compared to just $567,000 in Tennessee

- The Company's focus in 2008 will be to continue with offset seismic development, and leasing activity in Kansas. As a result, the Company's undeveloped location value and total number of locations are expected to grow.

The map below indicates the location of the Company's top six valued leases in Kansas as of December 31, 2007.

The following tables indicate the production from the Company’s top six leases in 2007 as well as the reserve value of these leases as of December 31, 2007. By comparing these tables with the tables below showing the total production from the Kansas Properties in 2007 and the Company’s aggregate reserve value as of December 31, 2007, 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

Total Oil Production 2007 185,188 Barrels

	LEASE	2007 Gross Production barrels	Company Net Revenue Interest	Percentage of Total Oil Production
1	Croffoot B	11,509	0.8203124	6%
2	Harrison A	9,537	0.875	5%
3	Stahl	7,407	0.84375	4%
4	Croffoot	7,360	0.861328	4%
5	Lewis	4,994	0.875	3%
6	Kraus A	4,239	0.8203125	2%

All Reserve Values are Stated in $1000's)

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

Value Of Company Proved Reserves $53,627,085

LEASE (Number of Producing Wells)	Proved Producing Value	Proved Undeveloped Value	Lease Total Value	Percentage of Total Lease Value to Company Proved Res

33

1	Croffoot (4)	$2,210.84	$1,322,99	**$3,533.84**	7%
2	Harrison A (5)	$2,205.43	$502.97	**$2,708.40**	5%
3	Lewis (3)	$1,522.53	$943.85	**$2,466.38**	5%
4	Croffoot B (6)	$1,646.58	$733.52	**$2,380.10**	4%
5	Kraus A (4)	$1,473.18	$377.73	**$1,850.91**	3%
6	Stahl (4)	$1,249.79	$401.24	**$1,651.03**	3%

Largest Kansas Lease by Reserve Value

Tennessee Properties

The Company's Swan Creek leases are on approximately 6,675 acres in Hancock, Claiborne and Jackson Counties in Tennessee. The decrease in the total volume of acreage of the Company’s Swan Creek leases from 8,635 acres at the end of 2006 is primarily due to the Company not renewing leases that were not in production. The initial terms of the Company’s Swan Creek leases vary from one to five years.

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. 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. The current published tariff rate is for firm transportation at a demand or “reservation” charge of five cents per MMBtu per day plus a commodity charge of $0.80 per MMBtu. 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, 2007, 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 that they were provided 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.

35

	Total Proved Reserves as of December 31, 2007			
	Producing	**Non-producing**	**Undeveloped**	**Total**
Natural gas (MMcf)	1,130	3.528	0	1,134
Oil (Bbls)	1,604,607	7,726	663,637	2,275,970
Total proved reserves (BOE)	1,792,940	8,314	663,637	2,464,970
Standardized measure of discounted future net cash flow	$37,803,144	$ 466,726	$ 15,357,217	$ 53,627,086

SEC regulations require that 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, 2007. 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, 2007 were $85.44 per barrel and $7.21 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, 2007. 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 standardized measure of future net cash flows associated with total proved reserves as of December 31, 2007 is stated to be $53,627,086. The LaRoche Report indicates the "proven developed producing" reserves for the Company as of December 31, 2007 to be as follows: net production volumes of 1,604,607 barrels of oil and 1,130 MMCF of gas compared to 1,358,532 barrels of oil and 1,264 MMCF of gas as reported by the Company at the end of 2006. The standardized measure of future net cash flows associated with total proved producing reserves as of December 31, 2007 is stated to be $37,803,144. The increase in oil reserves from 2006 to 2007 is reflective of the Company's increased drilling activities in Kansas in 2007 and future drilling plans including 39 future wells at proved undeveloped (PUD) locations. The decrease in gas reserves from 2005 is due primarily to the Company's determination not to drill any new wells in its Swan Creek Field and the drop in the price used to calculate the gas reserves from $8.33 per Mcf in 2006 to $7.21 per Mcf in 2007. For additional information concerning our estimated proved reserves, the standardized measure of discounted future net cash flows of the proved reserves at December 31, 2007, 2006 and 2005, and the changes in quantities and standardized measure of such reserves for each of the three years then ended; see Note 20 to our consolidated financial statements.

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 believes that the reserve analysis reports prepared by LaRoche for the Company's Kansas and Tennessee Properties provide an essential basis for review and consideration of the Company's producing properties by all potential industry partners and all financial institutions across the country. It is standard in the industry for reserve analyses such as these to be used as a basis for financing of drilling costs.

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.

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.

KANSAS Year Ended December 31	**Production**		**Cost of Production (per BOE)[3]**	**Average Sales Price**	
	Oil (Bbl)	**Gas (Mcf)[4]**		**Oil (Bbl)**	**Gas (Per Mcf)**
2007	178,311	-0-	$16.97	$85.53	-0-
2006	179,556	-0-	$13.05	$56.69	-0-
2005	128,765	20,729	$15.33	$53.48	$5.02

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

---

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 Figures in this column reflect the fact that the Company sold all of the gas producing wells on its Kansas Properties on March 4, 2005 effective as of February 1, 2005. Thus, gas production is only through January 2005.

38

2005	10,818	183,400	$18.86	$53.90	$8.74

Oil and Gas Drilling Activities

Kansas

In 2007, the Company drilled 16 new wells in Kansas, 15 of which were drilled in the third and fourth quarters. These wells included nine wells drilled in the Ten Well Program. The Company has a 100% working interest in the remaining seven wells drilled in Kansas in 2007. All wells drilled in 2007 have produced in the aggregate a cumulative total of 6,215 barrels of oil.

The results of the wells drilled in Kansas as of December 31, 2007 are set out in the following table. Unless otherwise indicated the Company has a 100% working interest in the wells.

NAME OF WELL	DATE COMPLETED	CUMULATIVE PRODUCTION (Bbl)
Mai #1	2-18-07	Dry Hole – Plugged (exploratory)
Lowry B #1	5-22-07	Dry Hole – Plugged
Dirks #2	7-9-2007	749.00
Howard #1	7-5-07	Dry Hole – Plugged (exploratory)
Hobrock #5	8-7-2007	1817.00
Veverka #1	8-17-07	Dry Hole – Plugged
Gilliland #1	8-28-07	Dry Hole – Plugged (exploratory)
Stahl A #1	10-16-2007	795.00*
Croffoot AA #1	10-19-2007	1285.00*
Veverka A #1	11-16-2007	75.00*
Croffoot BB #1	11-15-2007	863.00*
Howard #2	11-8-07	Dry Hole – Plugged* (exploratory)
Nutsch #1	12-6-2007	631.00*
Green #1	12-27-2007	0* (Exploration Discovery)
Veverka A #2	1-4-2008	0*
McElaney #1	1-24-08	0*(Exploration Discovery)

* 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 2007, 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 the Swan Creek Field. The Company believes that drilling new gas wells in the Field 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, 2005, 2006, and 2007 the number of gross and net development wells drilled by the Company. The wells drilled in 2007 refer to the nine wells drilled in the Ten Well Program as well as seven 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 gross wells.

YEAR ENDED DECEMBER 31	2007		2006		2005	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Kansas						
Productive Wells	10	4.0	9	5.055	7	0.9175
Dry Holes	6	5.25	1	.056	2	0.2163
Tennessee						
Productive Wells	0	0	0	0	0	0
Dry Holes	0	0	0	0	0	0

Productive Wells

The following table sets forth information regarding the number of productive wells in which the Company held a working interest as of December 31, 2007. 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	182	142
Tennessee	21	16.3	4	3.5

Developed and Undeveloped Oil and Gas Acreage

As of December 31, 2007, 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	12,150	10,002	16,784	13,285
Tennessee	1,525	1,250	5,151	4,224

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 2007.

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 American Stock Exchange ("AMEX") under the symbol TGC. The range of high and low closing prices for shares of common stock of the Company during the fiscal years ended December 31, 2007 and December 31, 2006 are set forth below.

For the Quarters Ending	**High**	**Low**
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
March 31, 2006	$ 1.18	$ 0.42
June 30, 2006	1.93	1.02
September 30, 2006	1.41	0.71
December 31, 2006	1.05	0.70

Holders

As of March 3, 2008 the number of shareholders of record of the Company's common stock was 333 and management believes that there are approximately 6,133 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 2007 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 2007, the Company issued 6,832 shares of its common stock pursuant to the exercise of warrants issued by the Company to a member of the plaintiff class as part of the settlement of the action entitled *Paul Miller v. M. E. Ratliff and Tengasco, Inc.*, United States District Court for the Eastern District of Tennessee, Knoxville, Docket Number 3:02-CV-644. Those warrants are exercisable for a period of three years from date of issue at $0.45 per share and are exempt from registration pursuant to section 3(a) (10) of the Securities Act of 1933, as amended. Any unregistered equity securities that were sold or issued by the Company during the first three quarters of Fiscal 2007 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 2007.

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 American Stock Exchange 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, 2002. 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

ITEM 6. SELECTED FINANCIAL DATA

The following selected financial data has 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,

	2007	**2006**	**2005**	**2004**	**2003**
Income Statement Data:					
Oil and Gas Revenues	$9,300,144	$8,896,036	$7,067,790	$6,013,374	$6,040,872
Production Cost and Taxes	$4,322,833	$3,287,233	$3,046,460	$3,364,429	$3,412,201
General and Administrative	$1,417,001	$1,293,109	$1,322,616	$1,777,183	$1,486,280
Interest Expense	$ 333,198	$ 168,590	$ 472,655	$1,367,180	$1,120,738
Net Income/Loss	$3,510,322	$2,141,364	$1,088,028	$(1,994,025)	$(3,197,662)
Net Income/Loss Attributable to Common Stockholders	$3,510,322	$2,141,364	$1,088,028	$(1,994,025)	$(3,451,580)
Net Income/Loss Attributable to Common Stockholder Per Share	$ 0.06	$ 0.04	$ 0.02	$ (0.05)	$ (0.29)

Year Ended December 31,[5],[6]

	2007	2006	2005	2004	2003
Balance Sheet Data:					
Working Capital Surplus (Deficit)	$ 2,473,476[7]	$872,507	$(1,334,744)	$(6,753,721)	$(10,822,717)
Oil and Gas Properties, Net	$13,209,601	$12,703,629	$ 9,675,977	$ 12,826,903	$12,989,443
Pipeline Facilities, Net	$12,916,667	$13,460,667	$13,994,453	$ 14,602,639	$15,139,789
Total Assets	$34,281,549	$28,454,338	$25,908,616	$ 28,209,749	$30,604,240
Long-Term Debt	$ 4,315,773	$ 2,730,534	$ 117,912	$ 1,940,890	$ 6,256,818
Redeemable Preferred Stock	$ -0-	$ -0-	$ -0-	$ -0-	$ -0-
Stockholders Equity	$28,102,871	$24,420,205	$ 21,961,454	$18,349,687	$11,251,871

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

Results of Operations

The Company incurred a net income to holders of common stock of $3,510,322 or $0.06 per share in 2007 compared to a net income of $2,141,364 or $0.04 per share in 2006 and compared to a net income of $1,088,028 or $0.02 per share in 2005. The Company recognized a tax benefit for net operating loss carry forwards in the amount of $2,100,000 in 2007.

The Company realized revenues of $9,368,624 in 2007 compared to $9,001,681 in 2006 and compared to $7,172,876 in 2005. Revenues increased $366,943 from 2006 due primarily to an increase in oil prices in Kansas; prices averaged $66.42 in 2007 and 60.84 in 2006. Gross oil production in 2007 was just slightly less than 2006 resulting from the loss of production in January 2007 due to the electricity outage during an ice storm. As a result of that storm, many counties in Kansas, including some counties where the Company has wells, lost power for the entire month of January. Producing wells in those counties were unable to produce without electricity to run the well pumps during the power outage. Consequently in January 2007 the Company saw production and revenue decline from monthly levels in late 2006. None of the Company’s producing wells were physically damaged by the ice storm or by non

---

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

[6] On July 1, 2003, the Company adopted the provisions of Statement of Financial Accounting Standards No. 150 under which mandatorily redeemable preferred stock shall be reclassified at estimated fair value to a liability. Thus, in 2003, it was determined that each of the Company’s series of preferred stock qualifies as shares subject to mandatory redemption and should be classified as a liability.

[7] 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 has expended approximately $1.5 million of these funds subsequent to year-end on the Methane Project and completing the Ten Well Program.

-

production during the absence of power, but the storm did substantially adversely impact production levels and sales in the first two months of 2007 while at the same time causing an increase in expenses. Eventually new poles and lines were rebuilt on a locally massive scale and electrical power was restored, and the Company experienced a rebound of production commencing in March 2007.

In 2007 the Company produced 178,311 barrels of oil in Kansas compared to 179,555 in 2006, a decrease of 1,244 barrels for the year. Additionally, the wells in the Eight Well Program (former Series “A”) reached the reversionary “flip point” in April 2007. This is the point at which the Company started receiving 85% of the participant’s interest plus our original interest of (19.3%) for an approximate total net interest to the Company equal to an 88% interest. In 2007 those wells produced 22,195 gross barrels of oil; the wells in the Twelve Well Program (former Series “B”) now converted to a six well program produced 15,864 gross barrels; wells polymered produced 19,502 barrels; and, the two new wells drilled produced 2,566 gross barrels in 2007. During 2007 the Company drilled 9 of the 10 wells in the Ten Well Program and produced 3,649 barrels from the 5 wells that were completed by year-end. The other three wells that were drilled in 2007 were then completed in 2008. In March 2008, the tenth and final well in the Ten Well Program was both drilled and completed as a producer. As of the date of this report, nine of ten wells drilled in the Ten Well Program have been completed as producers and are producing approximately 106 barrels per day. During the first half of 2008 the Company expects the reversionary flip point for the Twelve Well Program (former Series “B”) now converted to a six well program, to be achieved.

Gas prices received for sales of gas from the Swan Creek Field averaged $6.86 per Mcf in 2007, $7.27 per Mcf in 2006 and $8.74 per Mcf in 2005. Oil prices received for sales of oil from the Swan Creek field averaged $64.81 per barrel in 2007, and $60.39 per barrel in 2006, and. $53.90 per barrel in 2005.

Production costs and taxes in 2007 increased to $4,322,833 from $3,287,233 in 2006 and $3,046,460 in 2005. The difference is due to increased work-overs to increase production, increased taxes, and overall cost increases of supplies in the industry.

Depletion, depreciation, and amortization for 2007 was $1,631,468, a decrease from $1,911,416 in 2006 due to production volumes added to future reserves from drilling activities. Depletion, depreciation, and amortization increased to $1,911,416 in 2006 from $1,605,043 in 2005. The increase in 2006 was due to a change in focus by the Company toward drilling in Kansas rather than in Tennessee, therefore removing drilling and development locations in Tennessee.

The Company’s general and administrative costs of $1,417,001 in 2007 remained generally consistent with 2006 levels of $1,293,109 and 2005 levels of $1,322,616. The 2007, 2006 and 2005 costs included non-cash charges related to stock options of $116,476, $159,160 and $103,400 respectively.

The increase in interest expense in 2007 relates to the borrowing base increase of the Citibank credit facility in 2007. Interest expense for 2006 decreased significantly over 2005 levels. This was due to the conversion of the Company’s preferred stock, which was subject to mandatory redemption, into either interest in a drilling program, common stock or cash payoffs. As of December 31, 2006, the Company’s only debt financing were vehicle loans totaling $195,801 and the CitiBank loan of $2,600,000.

The Company’s public relations costs remained stable at $21,605 for 2007, compared to $26,037 for 2006 and $30,020 for 2005 as the Company continued to apply cost saving methods in the preparation of its annual report and in publishing of press releases.

Professional fees in 2007 were $232,197 compared to $173,932 in 2006. This was due to the Company commencing its review of its internal controls over its financial reporting in accordance with Item 308(T) of Regulation S-K. Professional fees in 2006 decreased from 2005 levels as the Company’s litigation was settled.

The Company recorded a deferred tax asset of $2,100,000 in 2007 relating to the Company’s net operating loss carry forwards. The Company recorded a gain on disposal of preferred stock of $655,746 in 2005.

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. in its own capacity and also as agent for other banks. 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. 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 interest of approximately 8.2%. Interest only was 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 Company used $1.393 million of the proceeds of the $2.6 million loan from Citibank to exercise the Company’s option to repurchase from Hoactzin Partners, L.P. (“Hoactzin”), the Company’s obligation to drill for Hoactzin the final six wells of the Company’s Twelve Well Program. Peter E. Salas, the Chairman of the Board of Directors of the Company, is the controlling person of Hoactzin. He is also the sole shareholder and controlling person of Dolphin Management, Inc., the general partner of Dolphin Offshore Partners, L.P., which is the Company’s largest shareholder. A detailed description of the Twelve Well Program is set forth In “Item 1 – Business” under the subheading “Kansas Drilling Programs”.

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 until payout as established under the terms of the Twelve Well Program. However, as a result of the terms of the repurchase option, Hoactzin will receive only a 6.25% overriding royalty in the next six Company wells to be drilled, plus an additional 6.25% overriding royalty in the six Program Wells that have previously been drilled. As a further result of the repurchase, the Twelve Well Program was converted into a six well program, and because six wells had been drilled by the Company as of June 30, 2006 the drilling obligation in this program was satisfied upon exercise of the repurchase option. Consequently, as of June 30, 2006, all well-drilling obligations of the Company owed to participants have been satisfied as to the Twelve Well Program (offered to Hoactzin and converted to a 6-well program upon the Company's repurchase of the obligation to drill the last six wells as described above) as well as the Company's earlier Eight Well Program (offered to the former Series A preferred stockholders).

Under the terms of the Eight Well Program and Twelve (now Six) Well program, upon payment to the participants of 80% of the value invested in the Program from proceeds from production, the participants will pay the Company a management fee of 85% of their proceeds. As to the Eight Well Program, that point was reached in April 2007 resulting in an increase in revenues from these wells to the Company of approximately $50,000 per month at current volumes and prices. As to the Twelve (now 6) Well Program, that point is expected to be reached during the first half of 2008. It is anticipated, based upon current volumes and prices that this will result in an increase in revenues to the Company of approximately $50,000 per month.

On April 19, 2007 the Company borrowed an additional $700,000 from Citibank under the existing Citibank revolving credit facility. The additional borrowing resulted from Citibank's increase in the Company's borrowing base under the credit facility from $2.6 million to $3.3 million as a result of Citibank's periodic borrowing base review conducted under the terms of credit facility. With the additional borrowing, the Company had borrowed the full amount of the $3.3 million borrowing base which was available to it under the Citibank revolving credit facility. Repayment of this additional sum was subject to the terms and conditions of the Citibank credit facility. The additional amount borrowed was used for additional development of the Company's producing properties.

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 will be 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 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.

The Company's initial borrowing on December 17, 2007 under its new facility with Sovereign was approximately $4.2 million which will bear interest at a floating rate equal to prime as published in the Wall Street Journal plus 0.25% resulting in a current interest rate of approximately 7.5%. Interest only is payable during the term of the loan and the principal balance of the loan is due December 31, 2010. 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 used a portion of the $4.2 million borrowed from Sovereign to pay off the funds it previously borrowed from Citibank. The remaining $900,000 borrowed from Sovereign was used to pay bank fees and attorney fees relating to the assignment in the amount of approximately $75,000 and the balance of approximately $825,000 was used to pay a portion of the purchase price for equipment to be utilized in the Methane Project currently under construction in Church Hill, Tennessee by MMC, the Company's wholly-owned subsidiary. See, "Item 1 - Business" under the subheading "The Methane Project".

Net cash provided by operating activities for 2007 was $3,446,677 compared to net cash provided by operating activities of $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 provided by operating activities for 2006 was $4,353,966 compared to net cash provided by operating activities of $2,113,763 in 2005. The Company's net income in 2006 increased to $2,141,364 from $1,088,028 in 2005. The impact on cash provided by operating activities was due to the net income for 2006 and was increased by non-cash depletion, depreciation, and amortization of $1,911,416 and by non-cash compensation and services paid by insurance of equity instruments of $159,160. Cash flow provided in working capital items in 2006 was $122,152 compared to cash used in working capital items of $209,601 in 2005. This resulted in 2006 from decreases from 2005 in accounts receivable of $434,565 offset by a decrease in other accrued liabilities of $251,327.

Net cash used in investing activities amounted to $3,145,764 for 2007 compared to net cash used in investment activities in the amount of $4,413,185 for 2006. The decrease in net cash used in investing activities during 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 used in investing activities amounted to $4,413,185 for 2006 compared to net cash provided by investment activities in the amount of $2,166,854 for 2005. The increase in net cash used in investing activities during 2006 was primarily attributable to an increase in oil and gas properties of $5,239,862 offset by a decreased drilling program portion of additional drilling costs of $1,067,400.

Net cash provided by financing activities increased to $1,556,261 in 2007 from cash provided by financing activities of $167,915 in 2006. In 2007 the primary sources of financing included proceeds from borrowings of $1,687,236 compared 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.

Net cash provided by financing activities increased to $167,915 in 2006 from cash used in financing activities of $4,287,383 in 2005. In 2006 the primary sources of financing included proceeds from borrowings of $2,732,145 compared to $155,075 in 2005. 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 customers, 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, 2006 or 2005.

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, 2007 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 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, the Company adopted FIN 48 on January 1, 2007. The Company does not expect the interpretation will have an impact on its results of operations or financial position.

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 SFAS 157, Fair Value Measurements. 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. Statement 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007. The Company continues to evaluate the impact the adoption of this statement could have on its 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 is considering the applicability of SFAS 159 and will determine if adoption is appropriate. The effective date for SFAS 159 is for fiscal years beginning after November 15, 2007.

CONTRACTUAL OBLIGATIONS

The following table summarizes the Company's contractual obligations at December 31, 2007:

Payments Due By Period

Contractual Obligations	Total	Less than 1year	1-3 years	3-5 years	More than 5 years
Long-Term Debt Obligations[8]	$4,373,660	57,887	$4,315,773	$-0-	$-0-
Capital Lease Obligations	$-0-	$-0-	$-0-	$-0-	$-0-
Operating Lease Obligations[9]	$31,673	$31,673	$-0-	$-0-	$-0-
Purchase Obligations	$-0-	$-0-	$-0-	$-0-	$-0-
Other Long-Term Liabilities	$-0-	$-0-	$-0-	$-0-	$-0-
Total	$4,405,333	$89,560	$4,315,773	$-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 $49.05 per barrel to a high of $89.18 per barrel during 2007. Gas price realizations ranged from a monthly low of $5.43 per Mcf to a monthly high of $7.59 per Mcf during the same period. The Company did not enter into any hedging agreements in 2007 to limit exposure to oil and gas price fluctuations.

8

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

9

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

Interest Rate Risk

At December 31, 2007, the Company had debt outstanding of approximately $4,373,660 including, as of that date, $4,200,000 owed on its credit facility with Citibank Texas, N. A., which was assigned on December 17, 2007 to Sovereign Bank. The interest rate on the credit facility is variable at a rate equal to LIBOR plus 2.5%. The Company’s remaining debt of $173,660 has fixed interest rates ranging from 5.5% to 8.25%. As a result, the Company's annual interest costs in 2007 fluctuated based on short-term interest rates on approximately 96% of its total debt outstanding at December 31, 2007. 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 $29,400, assuming borrowed amounts under the credit facility remained at the same amount owed as of December 31, 2007. The Company did not have any open derivative contracts relating to interest rates at December 31, 2007.

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 (T). CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

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

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, 2007 as required by the Securities Exchange Act of 1934 Rule 13a-15(c). 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, 2007.

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

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.

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, 2007 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 2008 Annual Meeting of Stockholders will be held on June 2, 2008 at 9:00 a.m. at the Homewood Suites by Hilton, 10935 Turkey Drive, Knoxville, Tennessee 37922. Proposals of stockholders sought to be presented at the 2008 annual meeting must be received in writing, by the Chief Executive Officer of the Company at the Company’s offices by the close of business on April 4, 2008 in order to be considered for inclusion in the Company's proxy statement relating to that meeting.

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 2008 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, 2007.

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	2,441,000	$0.30	39,368
Equity compensation plans not approved by security holders[10]	0	n/a	0
Total	2,441,000	$0.30	39,638

[10] 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 an amendment to the Plan to increase the aggregate number of shares that may be issued under the Plan from 1,000,000 shares to 3,500,000 shares. On February 1, 2008, the Company’s Board of Directors adopted further amendments to the Plan to increase the number of shares that may be issued under the Plan by 3,500,000 shares and to extend the Plan for another 10 years from October 24, 2010 to October 24, 2020. The Company’s shareholders will be requested to vote to approve these amendments at the upcoming Annual Meeting of the Company’s shareholders to be held on June 2, 2008.

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:

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	Asset Purchase Agreement dated March 4, 2005 between Tengasco, Inc. and Bear Petroleum, Inc. (Incorporated by reference to Exhibit 10.1 the registrant's current report on Form 8-K dated March 9, 2005 (the "March 9, 2005 Form 8-K")
10.8	Assignment and Bill of Sale between Tengasco, Inc. and Bear Petroleum, Inc. (Incorporated by reference to Exhibit 10.2 to the March 9, 2005 Form 8-K)

10.9	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)
10.10	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)
10.11	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"))
10.12	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.)
10.13	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)
10.14	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)
10.15*	Subscription Agreement of Hoactzin Partners, L.P. for the Company's ten well drilling program on its Kansas Properties dated August 3, 2007.
10.16*	Agreement and Conveyance of Net Profits Interest dated September 17, 2007 between Manufactured Methane Corporation as Grantor and Hoactzin Partners, LP as Grantee.
10.17*	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.
10.18*	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
10.19	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)
10.20*	Management Agreement dated December 18, 2007 between Tengasco, Inc. and Hoactzin Partners, L.P.
14	Code of Ethics (Incorporated by reference to Exhibit 14 to the registrant's annual report on Form 10-K filed March 30, 2004)
17.1	Letter of resignation of Clarke H. Bailey as a Director of the Company dated March 27, 2007 (Incorporated by reference to Exhibit 17.1 to the registrant's current report on Form 8-K dated March 27, 2007)
21*	List of subsidiaries
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 31, 2008

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	Director;	March 31 , 2008
Jeffrey R. Bailey	Chief Executive Officer	
s/Matthew K. Behrent	Director	March 31, 2008
Matthew K. Behrent		
s/John A. Clendening	Director	March 31, 2008
John A. Clendening		
s/Carlos P. Salas	Director	March 31, 2008
Carlos P. Salas		
s/Peter E. Salas	Director	March 31, 2008
Peter E. Salas		
s/Mark A. Ruth	Principal and Financial	March 31, 2008

Mark A. Ruth	Accounting Officer

Tengasco, Inc.
and Subsidiaries

Consolidated Financial Statements

Years Ended December 31, 2007, 2006 and 2005

Report of Independent Registered Public Accounting Firm	F-3
Consolidated Financial Statements	
Consolidated Balance Sheets	F-4 – F-5
Consolidated Income Statements	F-6
Consolidated Statements of Stockholders' Equity	F-7
Consolidated Statements of Cash Flows	F-8
Notes to Consolidated Financial Statements	F-9 – F-32

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders

Tengasco, Inc. and Subsidiaries

Knoxville, Tennessee

We have audited the accompanying consolidated balance sheets of Tengasco, Inc. and Subsidiaries as of December 31, 2007 and 2006 and the related consolidated statements of operations, changes in stockholders' equity and cash flows for each of the three years in the period ended December 31, 2007. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Tengasco, Inc. and Subsidiaries as of December 31, 2007 and 2006 and the results of their operations and cash flows for each of the three years in the period ended December 31, 2007 in conformity with accounting principles generally accepted in the United States of America.

/s/ Rodefer Moss & Co, PLLC

Knoxville, Tennessee

March 27, 2008

Tengasco, Inc. and Subsidiaries

Consolidated Balance Sheets

December 31,	**2007**	**2006**
Assets		
Current		
Cash and cash equivalents	**$ 2,226,839**	$ 369,665
Accounts receivable	**1,057,148**	719,840
Participant receivables	**49,872**	13,008
Inventory	**460,365**	550,522
Other current assets	**11,056**	11,056
Total current assets	**3,805,280**	1,664,091
Restricted cash	**120,500**	120,500
Loan fees	**223,733**	237,738
Oil and gas properties, net (on the basis of full cost accounting)	**13,209,601**	12,703,629
Pipeline facilities, net of accumulated depreciation of $3,423,099 and $2,879,099	**12,916,667**	13,460,667
Other property and equipment, net	**256,058**	267,713
Deferred Tax Asset	**2,100,000**	-
Methane Project	**1,649,710**	-
	$ 34,281,549	$ 28,454,338

See accompanying Notes to Consolidated Financial Statements

F-4

Tengasco, Inc. and Subsidiaries

Consolidated Balance Sheets

December 31,	**2007**	2006
Liabilities and Stockholders' Equity		
Current liabilities		
Current maturities of long term debt	**$ 57,887**	$ 65,267
Accounts payable	**903,238**	687,475
Accrued interest payable	**10,005**	8,432
Other accrued liabilities	**360,674**	30,410
Total current liabilities	**1,331,804**	791,584
Asset retirement obligations	**531,101**	512,015
Long term debt, less currentmaturities	**4,315,773**	2,730,534
Total liabilities	**6,178,678**	4,034,133
Stockholders' equity		
Common stock, $.001 par value; authorized 100,000,000 shares; 59,155,750 and 59,003,284 shares issued and outstanding	**59,156**	59,004
Additional paid-in capital	**54,689,525**	54,517,333
Accumulated deficit	**(26,645,810)**	(30,156,132)
Total Stockholders' equity	**28,102,871**	24,420,205
	$ 34,281,549	$ 28,454,338

See accompanying Notes to Consolidated Financial Statements

F-5

Tengasco, Inc. and Subsidiaries

Consolidated Income Statements

Years ended December 31,	**2007**	2006	2005
Revenues and other income			
Oil and gas revenues	**$ 9,300,144**	$ 8,896,036	$ 7,076,790
Pipeline transportation revenues	**51,492**	87,822	94,911
Interest Income	**16,988**	17,823	1,175
Total revenues and other income	**9,368,624**	9,001,681	7,172,876
Costs and expenses			
Production costs and taxes	**4,322,833**	3,287,233	3,046,460
Depreciation, depletion and amortization	**1,631,468**	1,911,416	1,605,043
General and administrative	**1,417,001**	1,293,109	1,322,616
Interest expense	**333,198**	168,590	472,655
Public relations	**21,605**	26,037	30,020
Professional fees	**232,197**	173,932	263,800
Total costs and expenses	**7,958,302**	6,860,317	6,740,594
Net Operating Income	**1,410,322**	2,141,364	432,282
Deferred Tax Benefit	**2,100,000**	-	-
Gain on Preferred Stock	**-**	-	655,746
Net Income	**$ 3,510,322**	$ 2,141,364	$ 1,088,028
Net Income per share			
Basic and diluted:			
Operations	**$ 0.06**	$ 0.04	$ 0.02
Total	**$ 0.06**	$ 0.04	$ 0.02
Shares used in computing earnings per share			
Basic	**59,117,176**	58,851,883	52,019,051
Diluted	**60,827,224**	60,364,797	52,659,051

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, 2005	48,927,828	48,928	51,686,283	(33,385,524)	18,349,687
Net Income	—	—	—	1,088,028	1,088,028
Common Stock issued for exercised options	100,000	100	26,900	—	27,000
Options Expense	—	—	84,030	—	84,030
Lawsuit Settlement	4,000	4	19,366	—	19,370
Conversion of Stock	9,567,620	9,568	2,381,418	—	2,390,986
Common Stock issued for exercise of Warrants	5,230	5	2,348	—	2,353
Balance, December 31, 2005	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

See accompanying Notes to Consolidated Financial Statements

Tengasco, Inc. and Subsidiaries

Consolidated Statements of Cash Flows

	2007	**2006**	2005
Operating activities			
Net	$**3,510,322**	**$ 2,141,364**	$ 1,088,028
Adjustments to reconcile net income to net cash			
Provided by operating activities:			
Depletion, depreciation, and amortization	**1,631,468**	**1,911,416**	1,605,043
Accretion of redeemable shares	**-**	**-**	242,008
Accretion on Asset Retirement Obligation	**70,929**	**42,340**	45,965
Gain on extinguishment of Asset Retirement Obligation	**-**	**-**	(72,399)
(Gain)/loss on sale of vehicles/equipment	**5,740**	**(22,466)**	(15,330)
Gain on exchange of Redeemable Liabilities	**-**	**-**	(655,746)
Gain on sale of pipeline facilities	**-**	**-**	(17,605)
Compensation and services paid in stock options	**116,476**	**159,160**	103,400
Deferred Tax Benefit	**(2,100,000)**	**-**	-
Changes in assets and liabilities:			
Accounts receivable	**(337,308)**	**434,565**	(447,653)
Participant receivables	**(36,864)**	**(3,231)**	63,239
Other current assets	**-**	**(5,000)**	61,470
Inventory	**90,157**	**(54,191)**	(154,586)
Accounts payable	**215,763**	**90,197**	277,458
Accrued interest payable	**1,573**	**8,432**	(25,367)
Other accrued liabilities	**330,264**	**(251,327)**	70,115
Settlement on Asset Retirement Obligations	**(51,843)**	**(97,293)**	(54,277)
Net cash provided by operating activities	**3,446,677**	**4,353,966**	2,113,763
Investing activities			
Additions to other property & equipment	**(172,443)**	**(137,924)**	(210,145)
Restricted cash	**-**	**(120,500)**	-
Decrease to other property & equipment	**17,000**	**27,915**	55,919
Net additions to oil and gas properties	**(5,190,611)**	**(5,239,862)**	(2,348,078)
Sale of Kansas gas field	**-**	**-**	2,651,770
Additions to Methane Project	**(1,649,710)**		
Drilling program portion of additional drilling	**3,850,000**	**1,067,400**	1,945,202
(Increase)/decrease in pipeline facilities	**-**	**(10,214)**	72,186
Net cash provided by (used in) investing activities	**(3,145,764)**	**(4,413,185)**	2,166,854
Financing activities			
Proceeds from exercise of options/warrants	**55,867**	**158,227**	29,352
Proceeds from borrowings	**1,696,444**	**2,732,145**	155,073
Loan fees	**(77,467)**	**(285,224)**	**-**
Repayments of borrowings	**(118,583)**	**(112,833)**	(3,182,636)
Proceeds from issuance of common stock	**-**	**-**	2,391,905

Dividends paid on Redeemable Liabilities	**-**	**-**	(8,000)
Repayments of Redeemable Liabilities	**-**	**-**	(4,241,874)
New Drilling Program	**-**	**-**	2,514,000
Decrease in Drilling Program liability		**(2,324,400)**	(1,945,203)
Net cash provided by (used in) financing activities	**1,556,261**	**167,915**	(4,287,383)
Net change in cash and cash equivalents	**1,857,174**	**108,696**	(6,766)
Cash and cash equivalents, beginning of period	**369,665**	**260,969**	267,735
Cash and cash equivalents, end of period	$**2,226,839**	**$ 369,665**	$ 260,969

F-8

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 solely for this purpose.

The Company is in the business of exploring for, producing and transporting 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.

In 1998, the Company acquired from AFG Energy, Inc. (“AFG”), a private company, approximately 32,000 acres of leases in the vicinity of Hays, Kansas (the “Kansas Properties”). Included in that acquisition were 273 wells, including 208 working wells, of which 149 were producing oil wells and 59 were producing gas wells, a related 50-mile pipeline and gathering system, three compressors and 11 vehicles. The Company sold the Kansas gas producing wells, gathering system and compressors effective February 1, 2005. During 2007, the Kansas Properties produced an average of 14,860 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 2007, the Company produced an average of 347 thousand cubic feet of natural gas per day and 573 barrels of oil per month from 21 producing gas wells and 5 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.

Tengasco, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

Basis of Presentation

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

F-10

Tengasco, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

Oil and Gas Properties

The Company follows the full cost method of accounting for oil and gas property acquisition, exploration, and development activities. Under this method, all 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 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 $3,110,768 in unevaluated properties as of December 31, 2007. 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 Ryder Scott Company, Petroleum Consultants in 2005 , and by LaRoche Petroleum Consultants Ltd. in 2006 and 2007.

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. No ceiling write-downs were recorded in 2007, 2006, or 2005.

Pipeline Facilities

Phase I of the pipeline was completed during 1999. Phase II of the pipeline was completed on March 8, 2001. Both phases of the pipeline were placed into service upon completion of Phase II. 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 three 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.

Tengasco, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

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, 2007, 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 $100,877 in 2007, $128,197 in 2006 and $84,030 in compensation expense in 2005 upon the Company’s adoption of SFAS 123 (R) in 2005.

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, 2007 and 2006 is necessary. However, actual write-offs may occur.

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 21,100,000.

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.

Tengasco, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

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.

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 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 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 2005, the Company received 74.6 percent of its revenues from Customer A; 18.6 percent of its revenues from Customer B.

In each of the years 2005 through 2007, 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 59,117,176, 58,851,883 and 52,019,051 weighted average shares outstanding for the years ended December 31, 2007, December 31, 2006 and December 31, 2005 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.

Tengasco, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

The number of dilutive shares outstanding is 1,710,048 for 2007, 1,512,914 for 2006 and 640,000 for 2005. 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.

(2.) Recent Accounting Pronouncements

In July 2006, the 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, 2004 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 SFAS 157, Fair Value Measurements. 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

Tengasco, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

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. Statement 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007. The Company continues to evaluate the impact the adoption of this statement could have on its 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 is considering the applicability of SFAS 159 and will determine if adoption is appropriate. The effective date for SFAS 159 is for fiscal years beginning after November 15, 2007.

(3). Related Party Transactions

In October, 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.

In 2006, the Company drilled four wells in the Twelve Well Program bringing the total number of wells drilled in that Program to six. All but one of those wells is continuing to produce commercial quantities of oil.

On June 29th, 2006 the Company closed a $50,000,000 credit facility with Citibank Texas, N.A. The Company’s initial borrowing base was set at $2,600,000 and the Company borrowed that amount on June 29, 2006 and used $1.393 million of the loan proceeds to exercise its option to repurchase from Hoactzin, the Company’s 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. Consequently, all well-drilling obligations of the Company under both the Eight Well and Twelve Well Programs with former preferred stockholders as participants have been satisfied.

Tengasco, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

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 will now receive 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.

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 $250,00 per drilled well that was non-productive. The terms of 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"). The Company will account for funds received for interests in the Program as an offset to oil and gas properties.

As of the date of this Report, the Company has drilled all ten wells in the Program. Of the ten wells drilled, nine were completed as oil producers and are currently producing approximately 84 barrels per day in total. Hoactzin paid a total of $3,850,000 for its interest in the 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 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 has been accelerated by Hoactzin agreeing to apply 75% of the net proceeds it receives from the methane extraction project being developed by the Company's wholly-owned subsidiary, Manufactured Methane Corporation, at the Carter Valley, Tennessee landfill to the Payout Point. (The methane extraction project is discussed in greater detail below.) Those 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.

Tengasco, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

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 5 years.

4. Oil and Gas Properties

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

December 31,	**2007**	2006
Oil and gas properties, at cost	**18,856,487**	$ 18,745,834
Unevaluated properties	**3,110,768**	1,880,811
Accumulation depreciation, depletion and amortization	**(8,757,654)**	(7,923,016)
Oil and gas properties, net	**13,209,601**	$ 12,703,629

During the years ended December 31, 2007, 2006 and 2005 the Company recorded depletion expense of $834,638, $1,144,711 and $902,131 in 2005.

5. 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 $536,000, in depreciation expense related to the pipeline for the years ended December 31, 2007, 2006 and 2005, respectively.

Tengasco, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

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.

This agreement expires in 2017 at which time the parties may renew the agreement for another 20-year term in consideration of similar inflation-adjusted payment terms.

6.

Other Property

and Equipment

Other property and equipment consisted of the following:

December 31	*Depreciable Life*	**2007**	2006
Machinery and equipment	5-7 yrs	$ 830,734	$ 771,767
Vehicles	2-5 yrs	487,176	521,824
Other	5 yrs	63,734	63,734
Total		1,381,644	1,357,325
Less accumulated depreciation		(1,125,586)	(1,089,612)
Other property and equipment - net		$ 256,058	$ 267,713

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

7. Long Term Debt

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

December 31,	**2007**	**2006**
Note payable to a financial institution, with interest payment only until maturity. (See Notes 15 & 16)	**$4,200,000**	$ 2,600,000

Installment notes bearing interest at the rate of 5.5% to 8.25% per annum collateralized by vehicles with monthly payments including interest of approximately $10,000 due through 2010.		
	173,660	**195,801**
Total long-term debt	**4,373,660**	**2,795,801**
Less current maturities	**(57,887)**	**(65,267)**
Long-term debt, less current maturities	**4,315,773**	$ **2,730,534**

F-18

Tengasco, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

8. Commitments and Contingencies

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

In the ordinary course of business the Company has entered into office leases which have remaining term of 6 months. Approximate future minimum lease payments to be made under non-cancelable operating leases in 2008 are $31,673.

Office rent expense for each of the three years ended December 31, 2007, 2006 and 2005 was approximately $63,346, $63,346, and $ 83,332 respectively.

9. Cumulative Convertible Redeemable Preferred Stock

On August 22, 2005 all holders of the Company's Series B and C Cumulative Convertible Preferred Stock (the "Series B and Series C shares"), having a total aggregate value of $5,113,045 consisting of face value, dividends, and interest exchanged all rights under their Series B and C shares for cash or for the Company's common stock. As a result of the exchange, as of August 22, 2005 the Company no longer had any holders of Series B or C preferred stock and no further obligations under any Series B or C shares. Holders of approximately 53.2% of the face value of outstanding Series B and C shares exchanged their preferred shares having an aggregate value of $2,721,140 for cash payments totaling $1,814,184. The Company obtained the funds for this exchange primarily from proceeds of a loan of $1,814,000 from Dolphin. The loan from Dolphin was evidenced by a secured promissory note dated August 22, 2005 bearing 12% interest per annum payable interest only monthly until the principal amount of the note was to become due on December 31, 2005. A second option offered to the Series B and C holders was to exchange their Series B and C shares for four shares of the Company's common stock for each dollar of the face value and unpaid accrued dividends and interest on their Series B and C shares. All of the holders, including Dolphin, of the remaining aggregate value of $2,391,905 or 46.8% of the Series B and C shares selected this option. As a result, a total of 9,567,620 shares of the Company's common stock were issued to those holders. Of this total number, 4,595,040 shares of unregistered common stock were issued to Dolphin in exchange for the $1,148,760 in aggregate value of the Series B shares held by Dolphin.

In total, the Company recorded a gain during 2005 from the exchange of Series A, B and C shares for cash and stock of $655,746, the difference between the carrying amount and the cash settlement amount and the stock issued.

Tengasco, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

10. 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.

On March 4, 2005 the Company sold its Kansas gas wells, and consequently the asset and the corresponding liability relating to asset retirement obligations on these wells were extinguished. The asset account was credited for $60,998 and the liability was removed in the amount of $133,397, creating a gain on the extinguishment of future obligations in the amount of $72,399, which was credited to interest expense.

The following is a roll-forward of activity impacting the asset retirement obligation for the year ended December 31, 2007:

Balance, December 31, 2005	$ 566,968
Accretion expense	42,340
Liabilities Settled	(97,293)
Balance, December 31, 2006	$ 512,015
Accretion expense	70,929
Liabilities Settled	(51,843)
Balance, December 31, 2007	$ 531,101

11. 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 3,500,000. Options are not transferable, are exercisable for 3 months after voluntary

Tengasco, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

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 2007, 2006 and 2005 is summarized below:

	2007		*2006*		*2005*	
	Shares	*Weighted Average Exercise Price*	*Shares*	*Weighted Average Exercise Price*	*Shares*	*Weighted Average Exercise Price*
Outstanding, beginning of year	**2,596,000**	**$ .31**	2,584,000	$ .29	295,153	$ 1.26
Granted	**0**		350,000	.60	2,500,000	.27
Exercised	**(126,000)**	**.42**	(338,000)	.42	(100,000)	.27
Expired/ canceled	**(29,000)**	**.64**	-	-	(111,153)	2.52
Outstanding and exercisable, end of year	**2,441,000**	**$ .30**	2,596,000	$ .31	2,584,000	$ .29

The following table summarizes information about stock options outstanding and exercisable at December 31, 2006:

Options Outstanding

Weighted Average Exercise Price		Weighted Average Remaining Contractual Life (years)	Options Exercisable
	Shares		*Shares*
$ 0.27	2,251,000	2.33	1,357,000
$ 0.58	110,000	3.05	110,000
$ 0.81	80,000	3.93	80,000

Tengasco, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

The weighted average fair value per share of options granted during 2006 and 2005 range from $0.15 to $0.32, calculated using the Black-Scholes Option-Pricing model. No options were granted in 2007.

Compensation expense of $84,030 related to stock options was recognized in 2005 and $128,197 in 2006 and 100,877 in 2007.

The fair value of stock options used to compute pro forma net loss and loss per share disclosures is the estimated present value at grant date using the Black-Scholes option-pricing model with the following weighted average assumptions for 2006 and 2005: expected volatility of 60% for 2006, and 2005; a risk free interest rate of 3.67% in 2006 and 2005; and an expected option life of 2.5 years for 2006 and 2005.

12. Income Taxes

The Company has taxable income for the periods ending December 31, 2007, December 31, 2006 and December 31, 2005.

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:

December 31,	**2007**	2006	2005
Statutory rate	**34%**	34%	34%
Tax (benefit)/expense at statutory rate	**1,193,000**	$ 728,000	$ 370,000
State income tax (benefit)/expense	**140,000**	85,000	43,000
Other	**3,000**	3,000	3,000
Non-deductible interest			-
Increase/(decreases)in deferred tax asset valuation allowance	**(3,436,000)**	(816,000)	(416,000)
Total income tax provision (benefit)	**(2,100,000)**	-	-

F-22

Tengasco, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

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

December 31	**2007**	2006	2005
Deferred tax assets:			
Net operating loss carryforward	**$7,314,000**	$ 8,700,000	$ 9,616,000
Capital loss carry forward	**263,000**	263,000	263,000
Total deferred tax assets	**7,577,000**	8,963,000	9,879,000
Deferred tax liability:			
Basis difference in pipeline	**250,000**	300,000	400,000
Total deferred liability	**250,000**	300,000	400,000
Total net deferred taxes	**7,327,000**	8,663,000	9,479,000
Valuation allowance	**(5,227,000)**	(8,663,000)	(9,479,000)
Net deferred tax asset	**$2,100,000**	-	-

As of December 31, 2007, Management, using the "more likely than not" criteria for recognition, elected to recognize a deferred tax asset of $2.1 million. The recognition of the deferred tax asset in 2007 relates to net operating loss carryforwards and will provide a better matching of income tax expense with taxable income in future periods. The current provision reflects the recognition of $1,336,000 current income tax benefit (fully offset by the current provision related to 2007 taxable income) and $2,100,000 in benefit relating to future periods.

No income tax expense was recognized for the years ended December 31, 2006 or December 31, 2005 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. Management continuously estimates the realization of the Company's deferred tax assets based on its anticipation of the likely timing and adequacy of future net income, after taking into consideration the increased uncertainty attributed to a lengthening horizon before the projected realization of future deferred assets.

As of December 31, 2007, the Company had net operating loss carry-forwards of approximately $21,100,000 which will expire between 2011 and 2023 if not utilized.

13. Supplemental Cash Flow Information

The Company paid approximately $262,268, $126,250, and $524,000, for interest in 2007, 2006 and 2005, respectively. No interest was capitalized in 2007, 2006 or 2005. No income taxes were paid in 2007, 2006, or 2005.

Tengasco, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

14. 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 expire 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.

15. 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.

Tengasco, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

$1.393 million of the $2.6 million loan proceeds were used by the Company on June 29, 2006 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 16).

On April 19, 2007 the Company borrowed an additional sum of $700,000 from Citibank, N.A. under its existing revolving credit facility dated June 29, 2006. 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. Repayment of this additional sum is subject to the terms and conditions of the Citibank credit facility. The additional amount borrowed will be used for further development of the Company's producing properties.

16. 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 will be 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 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.

The Company's initial borrowing on December 17, 2007 under its new facility with Sovereign was approximately $4.2 million which will bear interest at a floating rate equal to prime as published in the Wall Street Journal plus 0.25% resulting in a current interest rate of approximately 7.5%. Interest only is payable during the term of the loan and the principal balance of the loan is due December 31, 2010. 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 used a portion of the $4.2 million borrowed from Sovereign to pay off the funds it previously borrowed from Citibank. The remaining $900,000 borrowed from Sovereign was used to pay bank fees and attorney fees relating to the assignment in the amount of approximately $75,000 and the balance of approximately $825,000 was used to pay a portion of the purchase price for equipment to be utilized in the Methane Project currently under construction in Carter Valley, Tennessee by MCC, the Company's wholly-owned subsidiary.

Tengasco, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

17. 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"). 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 BFI in Church Hill, Tennessee. BFI's facility is located about two miles from the Company's existing pipeline serving Eastman Chemical Company ("Eastman"). Contingent upon obtaining suitable financing, the Company plans to acquire and install 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 plans to construct a small diameter pipeline to deliver the extracted methane gas to the Company's existing pipeline for delivery to Eastman (the "Methane Project").

MCC has placed equipment orders for its first stage of process equipment (cleanup and carbon dioxide removal) and the second stage of process equipment (nitrogen rejection) for the Methane Project. It is anticipated that the total costs for the Project including pipeline construction, will be approximately $4.1 million including costs for compression and interstage controls. The costs of the Methane Project to date have been 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 in the amount of approximately $1 million and (c) $825,000 of the funds the Company borrowed from its credit facility with Sovereign Bank. The Company anticipates that most of the remaining balance of the Methane Project costs will be paid from the Company's cash flow.

The Company anticipates that the equipment ordered by MMC will be manufactured and delivered to allow operations to begin in mid-2008 after equipment installation, testing, and startup procedures are begun. Commercial deliveries of gas will begin when the equipment is installed and tested and the pipeline is constructed. Upon commencement of operations, the methane gas produced by the project facilities will be mixed in the Company's pipeline and delivered and sold to Eastman Chemical Company ("Eastman") under the terms of the Company's existing natural gas purchase and sale agreement. At current gas production rates and expected extraction efficiencies, when commercial operations of the Project begin, the Company would expect to deliver about 418 MMBtu 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. At an assumed sales price of gas of $7 per MMBtu, near the average natural gas price received by the Company in 2007, the anticipated net revenues to the Company would be approximately $800,000 per year from the Methane Project based on anticipated volumes and expenses. The gas supply from this project is projected to grow over the years as the underlying operating

Tengasco, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

landfill continues to expand and generate additional naturally produced gas, and for several years following the closing of the landfill, currently estimated by BFI 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 Allied Waste Industries, an affiliate of BFI, 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. Allied Waste will pay the additional costs for including the water line. Construction of the gas pipeline needed to connect the facility with the Company's existing natural gas pipeline began in January 2008. As a certificated utility, the Company's pipeline subsidiary, TPC, requires no additional permits for the gas pipeline construction. The Company currently anticipates that pipeline construction will be concluded approximately the same time as equipment deliveries and installations occur or in the May to June 2008 time period, subject to weather delays during wintertime construction.

On September 17, 2007, Hoactzin, simultaneously with subscribing to participate in the Ten Well 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 will rapidly accelerate reaching the Payout Point. 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 provision to the Company in the overall transaction.

18. 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.

19. Quarterly Data and Share Information (unaudited)

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

Tengasco, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

Fiscal Year Ended 2007

	First Quarter	Second Quarter	Third Quarter(a)	Fourth Quarter(a)
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**

Fiscal Year Ended 2006

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	**$ 2,098,969**	**$ 2,354,736**	**$ 2,251,274**	**$ 2,296,702**
Net loss/income	**316,347**	**720,769**	**519,094**	**585,154**
Net loss/income attributable to common stockholders	**$ 316,347**	**$ 720,769**	**$ 519,094**	**$ 585,154**
Income/loss per common share	**$ 0.01**	**$ 0.01**	**$ 0.01**	**$ 0.01**

(a)

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.

20. 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 Ryder Scott Company, L.P. as of December 31, 2005, The reserves were estimated by LaRoche Petroleum Consultants Ltd. in 2006 and 2007.

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:

Tengasco, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

	2007	2006	2005
Property acquisitions			
Proved	**200,000**		
Unproved			-
Less –proceeds from	**-**		
Sales of properties		-	$ (2,651,770)
Development Cost	**4,990,611**	4,172,462	402,876
	5,190,611	$ 4,172,462	$ (2,248,894)

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,	**2007**	2006	2005
Revenues	**9,300,144**	$ 8,896,036	$ 7,076,790
Production costs and taxes	**(4,160,488)**	(3,145,244)	(2,956,307)
Depreciation, depletion and amortization	**(834,638)**	(1,144,711)	(902,132)
Income from oil and gas producing activities	**4,305,018**	$ 4,606,081	$ 3,218,351

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, 2007, 2006 and 2005 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.

Tengasco, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

	Oil (bbls)	*Gas (Mcf)*
Balance, December 31, 2004	1,090,000	7,947,000
Revisions of previous estimates	175,285	(629,633)
Improved Recovery	79,600	-
Purchase of Reserves in Place		
Extensions and Discoveries	174,130	-
Production	(144,552)	(204,128)
Sale of Reserves in Place	-	(2,350,000)
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
Proved developed producing reserves at.	1,604,607	1,130,869

resere

December 31, 2007		
Proved developed producing reserves at.	1,358,532	1,264,527
resere		
December 31, 2006		
	1,091,135	2,814,306
Proved developed producing reserves at.	1,091,135	2,814,306
resere		
December 31, 2005		

F-30

Tengasco, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

	Year Ended 12/31/07			Year Ended 12/31/06			Year Ended 12/31/05		
(amounts in thousands)	**Oil**	**Gas**	**Total**	**Oil**	**Gas**	**Total**	**Oil**	**Gas**	**Total**
Total proved reserves year-end reserve report	$52,117	$1,510	$53,627	$24,099	$2,370	$26,469	$23,530	13,649	$37,179
Proved developed producing reserves (PDP)	$36,319	$1,485	$37,804	$19,335	$2,370	$21,705	$18,721	$8,048	$26,769
% of PDP reserves to total proved reserves	67%	3%	70%	73%	9%	82%	50%	22%	72%
Proved developed non-producing reserves	$441	$25	$466	$529	$0	$529	$1,602	$3,603	$5,205
% of PDNP and PBP reserves to total proved reserves	1%	0%	1%	2%	0%	2%	4%	10%	14%
Proved undeveloped reserves (PUD)	$15,357	$0	$15,357	$4,235	$0	$4,235	$3,207	$1,998	$5,205
% of PUD reserves to total proved reserves	29%	0%	29%	16%	0%	16%	9%	5%	14%

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,	**2007**	2006	2005
Future cash inflows	**$ 206,276**	$ 107,291	$ 130,584
Future production costs and taxes	**(76,944)**	(52,033)	(55,625)
Future development costs	**(10,175)**	(4,505)	(1,494)
Future income tax expenses	**-**	-	-
Net future cash flows	**119,157**	50,753	73,465
Discount at 10% for timing of cash flows	**(65,530)**	(24,284)	(36,286)

Tengasco, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

Discounted future net cash flows from proved reserves	**$ 53,627**	$ 26,469	$ 37,179

(amounts in thousands)

	2007	2006	2005
Balance, beginning of year	**$ 26,469**	$ 37,179	$ 26,731
Sales, net of production costs and taxes	**(5,140)**	(5,751)	(4,121)
Discoveries and extensions	**1,166**	1,734	453
Purchases of Reserves	**568**	-	-
Changes in prices and production costs	**16,893**	(6,329)	13,537
Revisions of quantity estimates	**16,584**	(1,781)	4,559
Sale of Reserves	**-**	-	(4,856)
Interest factor - accretion of discount	**2,647**	3,718	2,673
Net change in income taxes	**-**	-	-
Changes in future development costs	**(5,669)**	(3,010)	262
Changes in production rates and other	109	709	(2,059)
Balance, end of year	**$ 53,627**	$ 26,469	$ 37,179

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 used at December 31, 2007, 2006, and 2005 were $85.44, $56.50, and $55.81, per barrel of oil and $7.21, $8.33 and $11.31 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, 2007, 2006 and 2005 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.