U.S. Securities and Exchange Commission
Washington, D.C. 20549
Form 10-Q

QUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF

THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2011

Commission File No. 1-15555

Tengasco, Inc.

(Exact name of issuer as specified in its charter)

Delaware	**87-0267438**
State or other jurisdiction of Incorporation or organization	**(IRS Employer Identification No.)**

11121 Kingston Pike, Suite E, Knoxville, TN 37934
(Address of principal executive offices)

(865-675-1554)

(Issuer's telephone number, including area code)

Indicate by check mark whether the issuer (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes X No__

Indicate by checkmark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§231.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). [X] Yes [ ] No

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

Large accelerated filer___ Accelerated filer ___
Non-accelerated filer ___ Smaller reporting company x
(Do not check if a smaller reporting company)

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: 60,737,413 common shares at November 4, 2011.

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Tengasco, Inc. and Subsidiaries
Condensed Consolidated Balance Sheets
(unaudited)
(in thousands, except share data)

	September 30, 2011	December 31, 2010
Assets		
Current		
Cash and cash equivalents	$ 71	$ 141
Accounts receivable	1,884	1,517
Accounts receivable – related party	460	993
Inventory	633	577
Deferred tax asset-current	-	264
Unrealized derivative asset-current	477	-
Other assets- current	84	33
Total current assets	3,609	3,525
Restricted cash	121	121
Loan fees, net	101	99
Oil and gas properties, net (full cost accounting method)	17,965	14,157
Pipeline facilities, net	6,909	7,041
Methane project, net	4,862	4,394
Other property and equipment, net	357	308
Deferred tax asset-noncurrent	8,795	10,095
Unrealized derivative asset-noncurrent	186	-
Other assets-noncurrent	31	9
Total assets	$ 42,936	$ 39,749

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

Tengasco, Inc. and Subsidiaries
Condensed Consolidated Balance Sheets
(unaudited)
(in thousands, except share data)

	September 30, 2011	December 31, 2010
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable – trade	$ 1,407	$ 550
Accounts payable – other	460	993
Accrued liabilities	623	571
Prepaid revenues – current	31	594
Current maturities of long-term debt	97	129
Unrealized derivative liability – current	-	687
Total current liabilities	2,618	3,524
Asset retirement obligation	1,416	1,437
Long term debt, less current maturities	11,026	9,564
Total liabilities	15,060	14,525
Stockholders' equity		
Common stock, $.001 par value; authorized 100,000,000 shares; 60,737,413 and 60,687,413 shares issued and outstanding	61	61
Additional paid–in capital	55,537	55,402
Accumulated deficit	(27,722)	(30,239)
Total stockholders' equity	27,876	25,224
Total liabilities and stockholders' equity	$ 42,936	$ 39,749

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

Tengasco, Inc. and Subsidiaries
Condensed Consolidated Statements of Operations
(unaudited)

(In thousands, except share and per share data)

	For the Three Months Ended September 30, 2011	For the Three Months Ended September 30, 2010	For the Nine Months Ended September, 30 2011	For the Nine Months Ended September, 30 2010
Revenues	$ 4,357	$ 3,286	$ 12,804	$ 9,429
Cost and expenses				
Production costs and taxes	1,516	1,551	4,718	4,401
Depreciation, depletion, and amortization	694	650	1,932	1,801
General and administrative	498	561	1,739	1,714
Total cost and expenses	2,708	2,762	8,389	7,916
Net income from operations	1,649	524	4,415	1,513
Other income (expense)				
Interest expense	(162)	(164)	(471)	(516)
Gain (loss) on derivatives	420	(89)	114	794
Gain on sale of assets	20	15	30	15
Total other income (expenses)	278	(238)	(327)	293
Income before income tax	1,927	286	4,088	1,806
Income tax expense	(741)	(98)	(1,571)	(614)
Net income	$ 1,186	$ 188	$ 2,517	$ 1,192
Net income per share				
Basic and diluted	$ 0.02	$ 0.00	$ 0.04	$ 0.02
Shares used in computing earnings per share				
Basic	60,693,935	60,687,413	60,689,611	60,324,346
Diluted	60,766,046	60,687,413	60,763,294	60,640,811

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

Tengasco, Inc. and Subsidiaries
Condensed Consolidated Statements of Stockholders' Equity
(unaudited)

(In thousands, except share data)

	Common Stock				
	Shares	Amount	Additional Paid in Capital	Accumulated Deficit	Total
Balance, December 31, 2010	60,687,413	$ 61	$ 55,402	$ (30,239)	$ 25,224
Net income	-	-	-	2,517	2,517
Option and compensation expense	-	-	107	-	107
Common stock issued for exercise of options	50,000	-	28	-	28
Balance, September 30, 2011	60,737,413	$ 61	$ 55,537	$ (27,722)	$ 27,876

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

Tengasco, Inc. and Subsidiaries
Condensed Consolidated Statements of Cash Flows
(unaudited)
(In thousands)

	For the nine months ended September 30, 2011	2010
Operating activities		
Net income	$ 2,517	$ 1,192
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, and amortization	1,932	1,801
Amortization of loan fees-interest expense	58	75
Accretion on asset retirement obligation	74	36
Loss (gain) on sale of assets	(30)	(15)
Compensation and services paid in stock options and stock	107	76
Deferred tax expense	1,564	614
Loss (gain) on derivatives	(114)	(794)
Changes in assets and liabilities:		
Accounts receivable	(368)	(128)
Accounts receivable – related party	533	(1,235)
Inventory	(56)	17
Other assets	(72)	(22)
Accounts payable-trade	856	(39)
Accounts payable-other	(533)	1,235
Accrued liabilities	53	168
Settlement on asset retirement obligation	(142)	(60)
Net cash provided by operating activities	6,379	2,921
Investing activities		
Net additions to pipeline facilities	-	(22)
Net additions to oil and gas properties	(5,891)	(2,400)
Net additions to methane project	(539)	-
Net additions to other property and equipment	(28)	(16)
Derivative costs and settlements	(1,236)	(29)
Net cash used in investing activities	(7,694)	(2,467)
Financing activities		
Repayments of borrowings	(138)	(470)
Proceeds from borrowings	1,415	-
Loan fees	(60)	(50)
Proceeds from exercise of options	28	15
Net cash provided by (used in) financing activities	1,245	(505)
Net change in cash and cash equivalents	(70)	(51)
Cash and cash equivalents, beginning of period	141	422
Cash and cash equivalents, end of period	$ 71	$ 371
Supplemental cash flow information:		
Cash interest payments	$ 413	$ 441
Supplemental non-cash investing and financing activities:		
Financed company vehicles	$ 154	$ 44

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

(1) Description of Business and Significant Accounting Policies

Tengasco, Inc. is a Delaware corporation ("Tengasco" or the "Company"). The Company is in the business of exploration and production of oil and natural gas. The Company's primary area of oil exploration and production is in Kansas. The Company's primary area of natural gas production is the Swan Creek Field in Tennessee.

The Company's wholly-owned subsidiary, Tengasco Pipeline Corporation ("TPC"), owns and operates a 65-mile intrastate pipeline which it constructed to transport natural gas from the Company's Swan Creek Field to customers in Kingsport, Tennessee.

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

Basis of Presentation

The accompanying unaudited condensed consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America ("U.S. GAAP") for interim financial information and with the instructions to Form 10-Q and Item 210 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by U.S. GAAP for complete financial statements. In the opinion of management, all adjustments (consisting of only normal recurring accruals) considered necessary for a fair presentation have been included. Operating results for the nine months ended September 30, 2011 are not necessarily indicative of the results that may be expected for the year ended December 31, 2011. For further information, refer to the Company's consolidated financial statements and footnotes thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 2010.

Principles of Consolidation

The accompanying consolidated financial statements are presented in accordance with U.S. GAAP. The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries after elimination of all significant intercompany transactions and balances.

Use of Estimates

The accompanying consolidated financial statements are prepared in conformity with U.S. GAAP which require management to make estimates and assumptions that affect the reported amounts of assets and liabilities 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

Revenues are recognized based on actual volumes of oil and gas sold to purchasers at a fixed or determinable price, when delivery has occurred and title has transferred and collectability is reasonably assured. Natural gas meters are placed at the customer's location and usage is billed each month. Crude oil is stored and at the time of delivery to the purchasers, revenues are recognized.

Cash and Cash Equivalents

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

Inventory

Inventory consists of crude oil in tanks and is carried at lower of cost or market value. In addition, the Company may also carry tubing, casing, and other equipment to be used in Kansas operations and is carried at lower of cost or market value. The Company recorded non-crude inventory of $0.12 million at September 30, 2011 and $0.01 million at December 31, 2010.

Reclassifications

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

(2) Income Taxes

Income taxes are reported in accordance with U.S. GAAP, which requires the establishment of deferred tax accounts for all temporary differences between the financial reporting and tax basis of assets and liabilities, using currently enacted federal and state income tax rates. In addition, deferred tax accounts must be adjusted to reflect new rates if enacted into law. Temporary differences result principally from federal and state net operating loss carry-forwards, differences in oil and gas property values resulting from a 2008 ceiling test write down, differences in pipeline values resulting from a 2010 impairment, and differences in methods of reporting depreciation and amortization.

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

Management periodically evaluates tax reporting methods to determine if any uncertain tax positions exist that would require the establishment of a loss contingency. A loss contingency would be recognized if it were probable that a liability has been incurred as of the date of the financial statements and the amount of the loss can be reasonably estimated. The amount recognized is subject to estimates and management's judgment with respect to the likely outcome of each uncertain tax position. The amount that is ultimately incurred for an individual uncertain tax position or for all uncertain tax positions in the aggregate could differ from the amount recognized. Management has determined that no significant uncertain tax positions existed as of September 30, 2011, and December 31, 2010.

At December 31, 2010, federal net operating loss carry forwards amounted to approximately $18.1 million which expire between 2016 and 2024. The total deferred tax asset at September 30, 2011 and December 31, 2010 was $8.8 million and $10.4 million, respectively. The Company has taken the conservative position and classified deferred tax assets related to net operating loss carryforwards as noncurrent.

(3) Earnings per Share

In accordance with Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 260, Earnings per Share, basic income (loss) per share is based on 60,693,935 and 60,687,413 weighted average shares outstanding for the quarters ended September 30, 2011, and September 30, 2010, respectively, and 60,689,611 and 60,324,346 weighted average shares outstanding for the nine months ended September 30, 2011 and September 30, 2010, 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 is reflected in diluted earnings per share for the quarters ended and nine months ended September 30, 2011 and September 30, 2010.

(4) Recent Accounting Pronouncements

In July 2010, the "Dodd-Frank Wall Street Reform and Consumer Protection Act" ("Wall Street Reform Act") was signed into law. The Wall Street Reform Act permanently exempts small public companies with less than $75 million in market capitalization (nonaccelerated filers) from the requirement to obtain an external audit on the effectiveness of internal financial reporting controls provided in Section 404(b) of the Sarbanes-Oxley Act of 2002. Section 404(b) requires a registrant to provide an attestation report on management's assessment of internal controls over financial reporting by the registrant's external auditor. Disclosure of management's assessment of internal controls over financial reporting under existing Section 404(a) is still required for nonaccelerated filers.

In February, 2010, the FASB issued Accounting Standards Update ("ASU") 2010-09, effective immediately, which amended ASC Topic 855, Subsequent Events. The amendment was made to address concerns about conflicts with SEC guidance and other practice issues. Among the provisions of the amendment, the FASB defined a new type of entity, termed an "SEC filer," which is an entity required to file with or furnish its financial statements to the SEC. Entities other than registrants whose financial statements are included in SEC filings (e.g., businesses or real estate operations acquired or to be acquired, equity method investees, and entities whose securities collateralize registered securities) are not SEC filers. While an SEC filer is still required by U.S. GAAP to evaluate subsequent events through the date its financial statements are issued, it is no longer required to disclose in the financial statements that it has done so or the date through which subsequent events have been evaluated. This update had no material impact on the Company's results of operations or financial position.

In January 2010, the FASB issued ASU 2010-06, "Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements". This update requires more robust disclosures about valuation techniques and inputs to fair value measurements. The update is effective for interim and annual reporting periods beginning after December 15, 2009. This update had no material effect on the Company's consolidated financial statements.

On December 31, 2008, the SEC published the final rules and interpretations updating its oil and gas reporting requirements ("Modernization of Oil and Gas Reporting"). In January 2010, the FASB released ASU 2010-03, Extractive Activities - Oil and Gas ("Topic 932"); Oil and Gas Reserve Estimation and Disclosures, aligning U.S. GAAP standards with the SEC's new rules. Many of the revisions were updates to definitions in the existing oil and gas rules to make them consistent with the petroleum resource management system, which is a widely accepted standard for the management of petroleum resources that was developed by several industry organizations. Key revisions include: (a) changes to the pricing used to estimate reserves utilizing a 12-month average price rather than a single day spot price which eliminates the ability to utilize subsequent prices to the end of a reporting period when the full cost ceiling was exceeded and subsequent pricing exceeds pricing at the end of a reporting period; (b) the ability to include nontraditional resources in reserves; (c) the use of new technology for determining reserves; and (d) permitting disclosure of probable and possible reserves. The SEC requires companies to comply with the amended disclosure requirements for registration statements filed after January 1, 2010, and for annual reports on Form 10-K for fiscal years ending on or after December 15, 2009. ASU 2010-03 is effective for annual periods ending on or after December 31, 2009. Adoption of Topic 932 did not have a material impact on the Company's results of operations or financial position. In April 2010, the FASB issued ASU 2010-14, Accounting for Extractive Activities-Oil & Gas: Amendments to Paragraph 932-10-S99-1. This ASU amends terminology as defined in Topic 932-10-S99-1.

(5) Related Party Transactions

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

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

In March 2008, the Company drilled and completed the tenth and final well in the Ten Well Program. Of the ten wells drilled, nine were completed as oil producers and are currently producing approximately 41 barrels per day in total. Hoactzin paid a total of $3.85 million (the "Purchase Price") for its interest in the Ten Well Program resulting in the Payout Point being determined as $5.2 million. The amount paid by Hoactzin for its interest in the Program wells exceeded the Company's actual drilling costs of approximately $2.8 million for the ten wells by more than $1 million.

Although production level of the Program wells will decline with time in accordance with expected decline curves for these types of wells, based on the drilling results of the wells in the Ten Well Program and the current price of oil, the Program wells would be expected to reach the Payout Point by December 31, 2013 solely from the oil revenues from the wells. However, under the terms of the Company's agreement with Hoactzin, reaching the Payout Point may be accelerated by operation of a second agreement by which Hoactzin will apply 75% of the net profits it may receive from a methane extraction project discussed below developed by the Company's wholly-owned subsidiary, Manufactured Methane Corporation ("MMC"), to the Payout Point. Those methane project net profits if applied may result in the Payout Point being achieved sooner than relying solely upon revenues from the Program wells. However, as discussed below, although the Methane Project has been placed into operation, no Methane Project net profits have been generated or paid to Hoactzin through September 30, 2011.

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

Through September 30, 2011, no payments have been made to Hoactzin for its 75% net profits interest in the Methane Project, because no net profits have been generated. The method of calculation of the net profits interest takes into account specific costs and expenses as well as gross revenues for the project. As a result of the startup costs and ongoing operating expenses, no net profits as defined in the agreement have been generated from project startup in April, 2009 through September 30, 2011 for payment to Hoactzin under the net profits interest conveyed. When the Payout Point is reached from either the revenues from the wells drilled in the Ten Well Program or Hoactzin's share of the net profits from the Methane Project or a combination thereof, Hoactzin's net profits interest in the Methane Project will decrease to a 7.5% net profits interest.

On September 17, 2007, the Company also entered into a third simultaneous agreement with Hoactzin providing that if the Program and the Methane Project interest in combination failed to return net revenues to Hoactzin equal to 25% of the Purchase Price it paid for its interest in the Ten Well Program by December 31, 2009, then Hoactzin would have an option to exchange up to 20% of its net profits interest in the Methane Project for convertible preferred stock to be issued by the Company with a liquidation value equal to 20% of the Purchase Price less the net proceeds received at the time of any exchange. At the time the agreement was negotiated, the Company's forecast of the probable results of the projects indicated that there was little risk that the option to acquire preferred stock would ever arise, so the Company placed no significant value to the preferred stock option. Since the beginning of 2011, the unrecovered invested amount has already been reduced by more than 20%, and therefore, Hoactzin is already precluded by these results from exercising its contingent option under the exchange agreement to convert into preferred in 2011. By September 30, 2011, the amount of net revenues received by Hoactzin from the Ten Well Program has reduced the Company's obligation to Hoactzin for the amount of the funds it had advanced for the Purchase Price from $3.85 million to $0.03 million. The conversion option would be set at issuance of the preferred stock at the then twenty business day trailing average closing price of Company stock on the NYSE Amex. Hoactzin has a similar option each year after 2009 in which Hoactzin's then-unrecovered Purchase Price at the beginning of the year is not reduced 20% further by the end of that year, using the same conversion option calculation at date of the subsequent year's issuance, if any. The Company, however, may in any year make a cash payment from any source in the amount required to prevent such an exchange option for preferred stock from arising. In addition, the conversion right is limited to no more than 19% of the outstanding common shares of the Company.

In the event Hoactzin's 75% net profits interest in the Methane Project were fully exchanged for preferred stock, by definition the reduction of that 75% interest to a 7.5%

net profits interest that was agreed to occur upon the receipt of 1.35 of the Purchase Price by Hoactzin could not happen because the larger percentage interest then exchanged, no longer exists to be reduced. Accordingly, Hoactzin would retain no net profits interest in the Methane Project after a full exchange of Hoactzin's 75% net profits interest for preferred stock.

Under this exchange agreement, if no proceeds at all were received by Hoactzin through 2009 or in any year thereafter (i.e. a worst-case scenario already highly unlikely in view of the success of the Program), then Hoactzin would have an option to exchange 20% of its interest in the Methane Project in 2010 and each year thereafter for preferred stock with liquidation value of 100% of the Purchase Price (not 135%) convertible at the trailing average price before each year's issuance of the preferred stock. The maximum number of common shares into which all such preferred stock could be converted cannot be calculated given the formulaic determination of conversion price based on future stock price. However, as of September 30, 2011, revenues from the Ten Well Program have resulted in 99% of the Purchase Price having already been reached. As noted above, no Methane Project net profits interest payments have been made to Hoactzin and the 99% of Purchase Price already reached has been accomplished solely from the Ten Well Program. Further, it is highly unlikely that any requirement to issue preferred stock will arise in 2011 or any succeeding years.

On December 18, 2007, the Company entered into a Management Agreement with Hoactzin. On that same date, the Company also entered into an agreement with Charles Patrick McInturff employing him as a Vice-President of the Company. Pursuant to the Management Agreement with Hoactzin, Mr. McInturff's duties while he is employed as Vice President of the Company will include the management on behalf of Hoactzin of its working interest in certain oil and gas properties owned by Hoactzin and located in the onshore Texas Gulf Coast, and offshore Texas and offshore Louisiana.

As consideration for the Company entering into the Management Agreement, Hoactzin agreed that it will be responsible to reimburse the Company for the payment of one-half of Mr. McInturff's salary, as well as certain other benefits he receives during his employment by the Company. In further consideration for the Company's agreement to enter into the Management Agreement, Hoactzin granted to the Company an option to participate in up to a 15% working interest on a dollar for dollar cost basis in any new drilling or workover activities undertaken on Hoactzin's managed properties during the term of the Management Agreement. The term of the Management Agreement ends on the earlier of the date Hoactzin sells its interest in its managed properties or five years (December 2012).

The Company became the operator of certain properties owned by Hoactzin in connection with the Management Agreement. The Company obtained from IndemCo, over time, bonds in the face amount of approximately $10.7 million for the purpose of covering plugging and abandonment obligations for operated properties located in federal offshore waters in favor of both the Bureau of Ocean Energy Management, Regulation and Enforcement, and certain private parties.

In connection with the issuance of these bonds the Company entered into a Payment and Indemnity Agreement with IndemCo that guarantees payment of any bonding liabilities incurred by IndemCo. Dolphin Direct Equity Partners, LP co-signed the Payment and Indemnity Agreement, thereby becoming jointly and severally liable with the Company for the obligations to IndemCo. Hoactzin has provided $6.6 million in cash to IndemCo as collateral for the obligations. Dolphin Direct Equity Partners is a private equity fund controlled by Peter E. Salas that has a significant economic interest in Hoactzin.

As operator, the Company has routinely contracted in its name for goods and services with vendors in connection with its operation of the Hoactzin properties. In practice, Hoactzin pays directly these invoices for goods and services that are contracted in the Company's name. During late 2009 and early 2010, Hoactzin undertook several significant operations, for which the Company contracted in the ordinary course. Payables related to these and ongoing operations remained outstanding at the end of the third quarter 2011 and 2010 in the amount of $0.5 million and $1.2 million respectively. Because this amount is material, the Company has recorded the Hoactzin-related payables and the corresponding receivable from Hoactzin as of September 30, 2011 in its Consolidated Balance Sheets under "Accounts payable – other" and "Accounts receivable – related party".

As a result of the operations performed in late 2009 and early 2010, Hoactzin currently has significant past due balances to several vendors, a portion of which are included on the Company's balance sheet. No Tengasco funds have been advanced by Tengasco to pay any obligations of Hoactzin. No borrowing capability of Tengasco has been or is expected to be used by the Company in connection with its obligations under the Management Agreement. The Company expects that Hoactzin will fully satisfy these obligations with its own resources. The Management Agreement terminates at the earlier of the date of sale, if any, by Hoactzin of its managed properties, or December 2012.

(6) Deferred Conveyance/Prepaid Revenues

The Company has adopted a deferred conveyance/prepaid revenues presentation of the transactions between the Company and Hoactzin Partners, L.P. on September 17, 2007 to more clearly present the effects of the three-part transaction consisting of the Ten Well Program, the Methane Project and a contingent exchange option agreement. To reflect the deferred conveyance, the Company allocated $0.85 million of the $3.85 million Purchase Price paid by Hoactzin for its interest in the Ten Well Program to the Methane Project, based on a relative fair value calculation of the Methane Project's portion of the projected payout stream of the combined two projects as seen at the inception of the agreement, utilizing then current prices and anticipated time periods when the Methane Project would come on stream. At inception of the Ten Well Program, the Company recorded $3.0 million to "Deferred conveyance oil and gas properties" and $0.85 million to "prepaid revenues".

Release of the deferred amounts to the Ten Well Program will be made as proceeds are actually distributed to Hoactzin. Release will be made on the respective proceeds only as to each project until either one or both satisfy the threshold amount that removes the contingent equity exchange option.

The reserve information for the parties' respective Ten Well Program interests as of December 31, 2010 is indicated in the table below. Reserve reports are obtained annually and estimates related to those reports are updated upon receipt of the report. These calculations were made using commodity prices based on the twelve month arithmetic average of the price on the first day of each month for the period January through December 2010 as required by SEC regulations. The table below reflects eventual pay as occurring through the realization of proceeds at a price of approximately $72.30 per barrel used in the reserve report dated December 31, 2010.

Reserve Information for Ten Well Program Interests for Year Ended December 31, 2010

	Barrels Attributable to Party's Interest MBbl	Future Cash Flows Attributable to Party's Interest (in thousands)	Present Value of Future Cash Flows Attributable to Party's Interest (in thousands)
Tengasco	69.4	$ 2,779	$ 1,022
Hoactzin Partners, L.P.	50.3	$ 2,367	$ 1,647

As of September 30, 2011 the original invested amount of $3.85 million has been reduced to $0.03 million which is reflected in "Prepaid revenues – current". Hoactzin's first right to convert its invested amount of $3.85 million into preferred stock was only exercisable to the extent Hoactzin's investment had not been reduced by 25% by the end of 2009. For each year after 2009 in which Hoactzin's then-unrecovered invested amount at the beginning of the year is not reduced 20% further by the end of that year, Hoactzin has a similar option. Since the beginning of 2011, the unrecovered invested amount has already been reduced by more than 20%, and therefore, Hoactzin is already precluded by these results from any possibility of exercising its contingent option under the exchange agreement to convert into preferred in 2011. In addition, the Company anticipates the remaining investment will be recovered by December 31, 2011, and therefore preclude Hoactzin from exercising its contingent option. All of the $3.82 million paid has been from the Ten Well Program with no payments made from the Methane Project, reducing the deferred conveyance account from $3.0 million to zero. The remaining payments will be applied against the prepaid revenue account.

As noted, in future periods, the Company anticipates that this Hoactzin investment will continue to be further reduced by sales of oil produced from the Ten Well Program, or methane produced from the Methane Project, or both. By December 31, 2011, the Company projects that the original $3.85 million Purchase Price will be reduced to zero. As a result, Hoactzin's contingent option to exchange for preferred stock would fully terminate without any further annual reduction tests. These projections are based upon expected production levels from the oil wells in the Ten Well Program using an $80 oil price, without any contribution from the Methane Project. The projection will vary with the actual oil prices, production volumes, and expenses experienced in 2011. Based on these projections the Company considers that it is unlikely that any right of Hoactzin to elect to exchange its Methane Project interest for Company preferred stock will ever arise.

However, in the event of a conversion of Hoactzin's Methane Project interest for Company preferred stock as set out in limited circumstances in the applicable agreement, and which the Company anticipates is highly unlikely, there would be a debit to the prepaid revenue account for both the Ten Well Program and Methane Project because no contingent option would remain on such a conversion and the Company would simultaneously credit preferred stock in the converted amount. In the event of the termination of the option to convert into preferred stock because the $3.85 million has been repaid from the Ten Well Program or Methane Project or both, the Ten Well Program account will be credited and the liability will be removed, as at this time the price received for the Program will be fixed and determinable.

(7) Oil and Gas Properties

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

	September 30, 2011	**December 31, 2010**
Oil and gas properties, at cost	$ 33,092	$ 27,837
Unevaluated properties	308	189
Accumulated depletion	(15,435)	(13,869)
Oil and gas properties, net	$ 17,965	$ 14,157

The Company recorded $1.6 million in depletion expense for the first nine months of 2011 and $1.3 million for the first nine months of 2010.

(8) Asset Retirement Obligation

The Company follows the requirements of FASB ASC 410, "Asset Retirement Obligations and Environmental Obligations". Among other things, FASB ASC 410 requires entities to record a liability and corresponding increase in long-lived assets for the present value of material obligations associated with the retirement of tangible long-lived assets. Over the passage of time, accretion of the liability is recognized as an operating expense and the capitalized cost is depleted over the estimated useful life of the related asset. The

Company's asset retirement obligations relate primarily to the plugging, dismantling and removal of wells drilled to date. The Company's calculation of Asset Retirement Obligation used a credit-adjusted risk free rate of 12%, when the original liability for wells drilled prior to 2009 was recognized. In 2009, the retirement obligations for new wells were recognized using a credit adjusted risk free rate of 8%. The retirement obligations for new wells drilled in January through July 2010 were recognized using a credit adjusted risk free rate of 6%. The retirement obligations for new wells drilled after July 2010 were recognized using a credit adjusted risk free rate of 5.25%. The Company used an estimated useful life of wells ranging from 10-40 years and an estimated plugging and abandonment cost of $11,000 per well in Kansas and $7,500 per well in Tennessee. Management continues to periodically evaluate the appropriateness of these assumptions.

(9) 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.

(10) Bank Debt

At September 30, 2011, the Company had a revolving credit facility with F&M Bank & Trust Company ("F&M Bank").

Under the credit facility, loans and letters of credit are available to the Company on a revolving basis in an amount outstanding not to exceed the lesser of $40 million or the Company's borrowing base in effect from time to time. The credit facility is secured by substantially all of the Company's producing and non-producing oil and gas properties and pipeline and the Company's Methane Project assets. The credit facility includes certain covenants in which the Company is required to comply. These covenants include leverage, interest coverage, minimum liquidity, and general and administrative coverage ratios. As of September 30, 2011, the Company was in compliance with all covenants.

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

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

On July 14, 2011, F&M Bank reaffirmed the Company's borrowing base at $20 million. The next borrowing base review will take place in January 2012. The total borrowing by the Company under the facility at September 30, 2011 and December 31, 2010 was $10.9 million and $9.5 million, respectively.

(11) Methane Project

On October 24, 2006, the Company signed a twenty-year Landfill Gas Sale and Purchase Agreement (the "Agreement") with BFI Waste Systems of Tennessee, LLC ("BFI"), an affiliate of Allied Waste Industries ("Allied").

In 2008, Allied merged into Republic Services, Inc. ("Republic"). The Company assigned its interest in the Agreement to MMC. The Agreement provides that MMC will purchase the entire naturally produced gas stream being collected at the Carter Valley municipal solid waste landfill owned and operated by Republic in Church Hill, Tennessee serving the metropolitan area of Kingsport, Tennessee. Republic's facility is located about two miles from the Company's pipeline. The Company installed a proprietary combination of advanced gas treatment technology to extract the methane component of the purchased gas stream. Methane is the principal component of natural gas and makes up about half of the purchased raw gas stream by volume. The Company constructed a pipeline to deliver the extracted methane gas to the Company's existing pipeline (the "Methane Project").

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

As part of the Methane Project agreement, the Company installed a new force-main water drainage line for Republic, the landfill owner, in the same two-mile pipeline trench as the gas pipeline needed for the Project, reducing overall costs and avoiding environmental effects to private landowners resulting from multiple installations of pipeline. Republic paid the additional material costs for the water line of approximately $0.7 million. As a certificated utility, the Company's pipeline subsidiary, TPC, required no additional permits for the gas pipeline construction.

MMC declared startup of commercial operations on April 1, 2009. During the month of April, the facility produced and sold 14 MMcf of methane gas to Eastman and was online about 91% of the calendar month.

System maintenance and landfill supply adjustments accounted for the remainder of the time. On May 1, 2009, Eastman advised MMC that it was suspending deliveries of the methane gas stream pending approval by the federal Environmental Protection Agency ("EPA") of Eastman's petition for inclusion of treated methane gas as natural gas within the meaning of the EPA's continuous emission monitoring rules applicable to Eastman's large boilers during the annual "smog season" beginning May 1 of each year. Although Eastman had begun seeking this approval in February, 2009, with the assistance of the Air Quality Department of the Tennessee Department of Environment and Conservation, the EPA had not acted by May 1. Eastman furnished to the EPA information provided by MMC that establishes that the methane gas stream is better fuel under the rule standards than even "natural" gas, which is technically defined in the smog season rules to include gas being "found in geologic formations beneath the earth's surface". Methane sales to Eastman were intended to resume upon EPA's formal approval of Eastman's petition or expansion of the regulatory definition, or both. Because approval was not received, MMC was forced to seek alternative markets for the methane gas stream.

The Company concluded an agreement for sale of the methane gas to Hawkins County Gas Utility, a local utility commencing August 1, 2009 on a month to month basis.

Effective September 1, 2009 the Company began sales of its Swan Creek gas production to Hawkins County Gas Utility District, because the physical mixing of Swan Creek natural gas with MMC's methane gas caused Eastman to not accept delivery of both categories of gas as mixed.

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

The Methane Project is designed to be capable of producing a daily average of about 500 MMBtu/day of methane from the Carter Valley landfill assuming the raw gas volumes being generated underground and collected in Republic's piping and collection system are sufficient to do so. However, in order to produce maximum levels on a given day, the raw gas volume must be available and the plant needs to remain in operation for the full 24 hours that day. Daily production decreases on days when the plant operates less than a full 24 hours, whether due to any equipment or collection system supply issue. The primary reason experienced for less-than-full-24-hour operation since April 2009 has been frequent spiking in the oxygen content in the raw gas collected by Republic and delivered to the plant, and not to equipment malfunctions in MMC's plant. Oxygen spikes shut down MMC's equipment for safety reasons as high oxygen gas is explosive in our treatment process.

In mid-2010, the oxygen spikes increased from occasional spikes to an almost constant high level of oxygen that caused longer downtime to our equipment. During the first quarter of 2011, the oxygen spikes continued throughout the quarter, with the plant only being able to produce during a two week period in March 2011 or about 13% of the total hours during the first quarter.

Similarly, during the second quarter of 2011, production occurred for only 19% of total hours during the quarter, due primarily to oxygen levels in the raw gas, as well as rising water levels in the collection system choking back volumes of gas available for delivery to MMC's treatment equipment. To attempt to increase volumes by pulling higher vacuum on the collection system when this additional high water circumstance arises would introduce water into our treatment equipment and damage plant equipment.

In the third quarter of 2011, the plant operated for only 26% of the total hours during the quarter for primarily the same reasons. Plant maintenance did cause a portion of the production downtime due to need to obtain unscheduled replacement parts not normally kept on hand.

Republic commenced a major gas collection system repair and rework in September 2011 and anticipates more adequately addressing both these oxygen and water problems. Simultaneously, Republic planned to drill additional gas collection wells in the landfill. The repairs should reduce air and water intrusion and allow MMC's plant to avoid shutdowns for safety and increase run time and consequently increase produced methane volumes. The new wells are due primarily to the growth of the working landfill, and should result in previously undelivered volumes of raw gas being sent to MMC's plant, so methane production volumes should additionally increase as a result of the new wells. As of the date of this Report, we are advised by Republic that four new wells have been drilled in the landfill, and the other collection system repairs are near completion. The Company anticipates that Republic's collection system may continue to require repairs from time to time and no assurances can be made concerning when Republic's system repairs may again be needed and if so, when such repairs may be concluded. If such additional repairs become necessary, until such time that the repairs are completed, the Company anticipates that only intermittent and minimal volumes would be produced.

In addition to the further system repairs being performed by Republic on its gas collection system, MMC determined to also address the high-oxygen level problem experienced to date by rerouting a portion of the recycle gas stream from MMC's plant operation to fuel electric generation at the plant site. This is anticipated to have a dual benefit to MMC of (1) offsetting significant electricity costs incurred to run the large 300-horsepower compressors needed to refine the methane, and (2) increasing overall run time of the methane plant and consequently increasing overall methane production. Plant run time is anticipated to increase because rerouting this existing recycle gas stream should reduce the oxygen level at plant inlet by about one half percent, thereby causing significantly fewer shutdowns for high oxygen at MMC's plant inlet. The increased run times are expected to fully offset the reduction in methane production efficiency necessarily caused by rerouting the recycle gas stream for use as generator fuel. The installation of the equipment required to reroute the recycle gas stream and fuel a generator is currently anticipated to be completed in the fourth quarter of 2011. MMC anticipates, but cannot assure, that when completed, the combined effects of new landfill wells, the Republic workover of its collection system, and the plant configuration to alter the recycle gas usage may result in significant improvement in the economic performance of the MMC plant.

On September 17, 2007, Hoactzin, simultaneously with subscribing to participate in the Ten Well Program (the "Program"), pursuant to a separate agreement with the Company was conveyed a 75% net profits interest in the Methane Project. Any net profits from the Methane Project, if received by Hoactzin, would be applied towards the determination of the Payout Point (as defined above) for the Ten Well Program. When the Payout Point is reached from either the revenues from the wells drilled in the Program or the Methane Project or a combination thereof, Hoactzin's net profits interest in the Methane Project will decrease to 7.5%. The agreed method of calculation of net profits takes into account specific costs and expenses as well as gross revenues for the project. As a result of the production levels discussed above, no net profits as defined have been generated from project startup in April, 2009 through September 30, 2011 for payment to Hoactzin under the net profits interest conveyed.

As stated above, the Purchase Price paid by Hoactzin for its interest in the Program exceeded the Company's actual costs of drilling the ten wells in the Program. Those excess funds provided by Hoactzin were used to pay for approximately $1 million of equipment required for the Methane Project, or about 22% 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.

(12) Fair Value Measurements

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

Level 1 inputs to the valuation methodology are unadjusted quoted prices for identical assets or liabilities in active markets.

Level 2 inputs to the valuation methodology include:

- Quoted prices for similar assets or liabilities in active markets; Quoted prices for identical or similar assets or liabilities in inactive markets;
- Inputs other than quoted prices that are observable for the asset or liability;
- Inputs that are derived principally from or corroborated by observable market data by correlation or other means. If the asset or liability has a specified (contractual) term, the Level 2 input must be observable for substantially the full term of the asset or liability.

Level 3 inputs to the valuation methodology are unobservable for the asset or liability and generally require fair value assumptions by management.

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

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

The following table sets forth by level, within the fair value hierarchy, the Company's assets and liabilities at fair value as of September 30, 2011 (in thousands):

	Level 1	Level 2	Level 3
Derivative assets	$ -	$ 663	$ -
Derivative liabilities	$ -	$ -	$ -
Net assets and liabilities at fair value	$ -	$ 663	$ -

(13) Derivatives

On July 28, 2009, the Company entered into a two-year agreement on crude oil pricing applicable to a specified number of barrels of oil that then constituted approximately two-thirds of the Company's daily production. Due to increased production levels, as well as a drop in the specified monthly barrels from 9,500 to 7,375 in 2011, this number of barrels constituted less than half of the Company's average daily production for the quarter ended September 30, 2011. As of August 1, 2011 the "costless collar" agreement has expired, however, the Company entered into an alternative hedging arrangement described below.

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

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

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

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

As of September 30, 2011, the Company's open forward positions on our outstanding "put" agreements with Cargill, were as follows *(fair value is based on methodology described in footnote 12 Fair Value Measurement):*

Period	Monthly Volume Oil (Bbls)	Total Volume Oil (Bbls)	Floor/Cap NYMEX $ per Bbl	Fair Value at September 30, 2011 (in thousands)
4th Qtr 2011	10,000	30,000	$65.00-N/A	$ 38
1st Qtr 2012	10,000	30,000	$65.00-N/A	$ 109
2nd Qtr 2012	10,000	30,000	$65.00-N/A	$ 151

3rd Qtr 2012	10,000	30,000	$65.00-N/A	$ 179
4th Qtr 2012	10,000	30,000	$65.00-N/A	$ 186
				$ 663
			Current Asset	$ 477
			Non Current Asset	$ 186

Management has engaged Risked Revenue Energy Associates to perform an independent valuation of the Fair Value of the Company's open forward positions. The Company records changes in the unrealized derivative asset or liability as a "Gain (loss) on derivatives" in the Consolidated Statements of Operations. The Company recorded a $0.54 million unrealized gain for the quarter ended September 30, 2011 and a $(0.09) million unrealized loss for the quarter ended September 30, 2010. During the first nine months of 2011 the Company recorded a $0.98 million unrealized gain and a $0.37 million purchase of a $65 floor, compared to recording a $0.82 million unrealized gain during the first nine months of 2010.

The following settlement payments related to the "costless collar" were made by the Company in 2011 (in thousands):

Payments	Production Month	Payment Month
$ 59.6	January 2011	February 2011
60.8	February 2011	March 2011
158.4	March 2011	April 2011
210.5	April 2011	May 2011
146.4	May 2011	September 2011
109.1	June 2011	July 2011
116.8	July 2011	August 2011
Total $ 861.6		

These realized losses were recorded as a "Gain (loss) on derivatives" in the Consolidated Statements of Operation. During the first nine months of 2010, the Company made settlement payments of $0.03 million.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Results of Operations and Financial Condition

During the first nine months of 2011, the Company sold 175 MBbl of oil from its Kansas wells. Of the 175 MBbl, 139 MBbl were net to the Company after required payments to all of the royalty interests and drilling program participants. The Company's net sales for the first nine months of 2011 of 139 MBbl of oil compares to 123 MBbl net to the Company's interest in the first nine months of 2010. This 16 MBbl increase was due primarily to increased sales volumes on the Croffoot B, Hutton, Veverka B, Veverka C, Veverka D, and various other leases. The Company's net revenue from the Kansas properties was $12.3 million in the first nine months of 2011 compared to $8.7 million in 2010. This increase was due to an increase in oil prices from an average of $70.22 per barrel in 2010 to an average of $88.22 per barrel in 2011, as well as the 16 MBbl increase in sales volumes. For the first nine months of 2011 and 2010, the Company's sales included $0.3 million from Swan Creek, and MMC revenues of $0.2 million and $0.3 million for 2011 and 2010, respectively.

Comparison of the Quarters Ended September 30, 2011 and 2010

The Company recognized $4.4 million in revenues during the third quarter of 2011 compared to $3.3 million in the third quarter of 2010. The increase in 2011 revenues was primarily due to a 5 MBbl increase in sales volumes as well as a $13.85 per barrel increase in Kansas oil prices. Kansas oil prices in the third quarter of 2011 averaged $82.49 per barrel compared to $68.64 per barrel in the third quarter of 2010. The Company realized net income attributable to common shareholders of $1.2 million or $0.02 per share of common stock during the third quarter of 2011, compared to a net income in the third quarter of 2010 to common shareholders of $0.2 million or $0.00 per share of common stock. In the third quarter of 2011, the Company had income from operations of $1.6 million compared to income from operations of $0.5 million in the third quarter of 2010. The increase in net income attributable to common shareholders and the increase in income from operations were primarily due to the increase in Kansas sales volumes and oil prices as well as $0.5 increase in gain on derivatives.

Production costs and taxes in the third quarter of 2011 was $1.52 million and was $1.55 million in the third quarter 2010. Although, the Company had higher repair costs in 2011, these costs were offset by a $0.2 million franchise tax refund for the period 2007-2010.

Depreciation, depletion, and amortization expense was $0.69 million and $0.65 million for the third quarters of 2011 and 2010, respectively.

General and administrative costs were $0.50 million for the third quarter of 2011 and $0.56 million for the third quarter of 2010.

During the third quarter of 2011, the Company recorded a $0.54 million non-cash unrealized gain on derivatives, and a $(0.12) million realized loss on derivatives, compared to a $(0.09) million non-cash unrealized loss on derivatives for the third quarter 2010. Interest expense was $0.16 million for each of the third quarters of 2011 and 2010.

Comparison of the Nine Months Ended September 30, 2011 and 2010.

The Company recognized $12.8 million in revenues during the first nine months of 2011 compared to $9.4 million in the first nine months of 2010. The increase in revenues was primarily due to an increase in oil prices in 2011, as well as a 16 MBbl increase in sales volumes. Oil prices in the first nine months of 2011 averaged $88.22 per barrel compared to $70.22 per barrel in the first nine months of 2010. The Company realized net income attributable to common shareholders of $2.5 million or $0.04 per share of common stock during the first nine months of 2011 compared to a net income in the first nine months of 2010 to common shareholders of $1.2 million or $0.02 per share of common stock. During the first nine months of 2011, the Company had income from operations of $4.4 million compared to income from operations of $1.5 million during the first nine months of 2010. The increase in net income attributable to common shareholders and the increase in income from operations were primarily due to the increase in Kansas sales volumes and higher oil prices, partially offset by increases in costs and expenses of $0.5 million. This increase in net income was also partially offset by a $0.7 million decrease in gain on derivatives.

Production cost and taxes in the first nine months of 2011 increased to $4.7 million from $4.4 million in the first nine months of 2010. This increase was due to higher 2011 property taxes and repair cost partially offset by a $0.2 million franchise tax refund for the period 2007-2010.

Depletion, depreciation, and amortization expense for the first nine months of 2011 was $1.9 million compared to $1.8 million in the first nine months of 2010.

General and administrative costs were $1.7 million for the first nine months of 2011 and 2010.

During the first nine months of 2011, the Company recorded a $0.98 million non-cash unrealized gain on derivatives, a $(0.86) million realized loss on derivatives, and purchased a $65 floor for $0.37 million, compared to a $0.82 million non-cash unrealized gain on derivatives and a $(0.03) million realized loss on derivatives during the first nine months of 2010. Interest expense was $0.47 million and $0.52 million for the first nine months of 2011 and 2010, respectively.

Liquidity and Capital Resources

At September 30, 2011, the Company had a revolving credit facility with F&M Bank & Trust Company (“F&M Bank”).

Under the credit facility, loans and letters of credit are available to the Company on a revolving basis in an amount outstanding not to exceed the lesser of $40 million or the Company’s borrowing base in effect from time to time. The credit facility is secured by substantially all of the Company’s producing and non-producing oil and gas properties, the Company’s pipeline and Methane Project assets. The credit facility includes certain covenants in which the Company is required to comply. These covenants include leverage, interest coverage, minimum liquidity, and general and administrative coverage ratios. As of September 30, 2011, the Company was in compliance with all covenants.

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

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

On July 14, 2011, F&M Bank reaffirmed the Company's borrowing base at $20 million. The next borrowing base review will take place in January 2012.

The total borrowing by the Company under the facility at September 30, 2011 and December 31, 2010 was $ 10.9 million and $9.5 million, respectively.

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

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

During the first nine months of each year, net cash provided by operating activities was $6.4 million in 2011 and $2.9 million in 2010. The increase of cash provided by operating activities from 2010 to 2011 was primarily due to higher product prices received during 2011 compared to 2010, increased sales volumes, and increased cash flow provided by working capital. Cash flow provided by working capital was $0.27 million in 2011 and $(0.06) million was used in working capital in 2010 due primarily to an increase in accounts payable related to increased activity levels in the first nine months of 2011. Net cash used in investing activities was $(7.7) million in 2011 and $(2.5) million in 2010. Cash flow provided by financing activities during the first nine months of 2011 was $1.2 million compared to $(0.5) million used in financing activities during the first nine months of 2010. The change in investing and financing activities was primarily due to an increase in drilling and polymer work performed in 2011. In addition, the increase in cash used in investing activities was also a result of derivatives costs of $0.37 million and settlements of $0.86 million during 2011.

Critical Accounting Policies

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

Revenue Recognition

Revenues are recognized based on actual volumes of oil and gas sold to purchasers at a fixed or determinable price when delivery has occurred and title has transferred, and collectability is reasonably assured. Natural gas meters are placed at the customer's location and usage is billed each month. Crude oil is stored and at the time of delivery to the purchasers, revenues are recognized.

Inventory

Inventory consists of crude oil in tanks and is carried at lower of cost or market value. In addition, the Company may also carry tubing, casing, and other equipment to be used in Kansas operations and is carried at lower of cost or market value.

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 costs of drilling, completing and equipping oil and gas wells. However, costs 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 an average price (arithmetic average of the beginning of the month prices for the prior 12 months) 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) cost of properties not being amortized; and (c) the lower of cost or estimated fair value of unproven properties included in the cost being amortized.

Oil and Gas Reserves / Depletion of Oil and Gas Properties

The Company's proved oil and gas reserves as of December 31, 2010 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.

The capitalized costs of oil and gas properties, plus estimated future development costs relating to proved reserves and estimated costs of plugging and abandonment, net of costs relating to proved reserves and estimated costs of plugging and abandonment, and 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.

Asset Retirement Obligations

The Company follows the requirements of FASB ASC 410, "Asset Retirement Obligations and Environmental Obligations". Among other things, FASB ASC 410 requires entities to record a liability and corresponding increase in long-lived assets for the present value of material obligations associated with the retirement of tangible long-lived assets.

Over the passage of time, accretion of the liability is recognized as an operating expense and the capitalized cost is depleted over the estimated useful life of the related asset. The Company's asset retirement obligations relate primarily to the plugging, dismantling and removal of wells drilled to date. The Company's calculation of Asset Retirement Obligation used a credit-adjusted risk free rate of 12%, when the original liability for wells drilled prior to 2009 was recognized. In 2009, the retirement obligation for new wells were was recognized using a credit adjusted risk free rate of 8%. The retirement obligations for new wells drilled in January through July 2010 were recognized using a credit adjusted risk free rate of 6%. The retirement obligations for new wells drilled after July 2010 were recognized using a credit adjusted risk free rate of 5.25%.

The Company used an estimated useful life of wells ranging from 10-40 years and an estimated plugging and abandonment cost of $11,000 per well in Kansas and $7,500 per well in Tennessee. Management continues to periodically evaluate the appropriateness of these assumptions.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISKS

The Company's Borrowing Base under its Credit Facility may be reduced by the lender.

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

As a result, the Company's ability to replace production may be limited. In addition, if the borrowing base is reduced, the Company may be required to pay down its borrowings under the revolving credit facility so that outstanding borrowings do not exceed the reduced borrowing base. This requirement could further reduce the cash available to the Company for capital spending and, if the Company did not have sufficient capital to reduce its borrowing level, could cause the Company to default under its revolving credit facility. As of September 30, 2011, the Company's borrowing base was set at $20 million of which $10.9 million had been drawn down by the Company. The Company's next periodic borrowing base review is scheduled to occur in January 2012.

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 Kansas oil prices received during the first nine months of 2011 ranged from a low of $79.04 per barrel to a high of $103.18 per barrel.

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

On July 28, 2009, the Company entered into a two-year derivative agreement on crude oil pricing applicable to a specified number of barrels of oil that then constituted about two-thirds of the Company's daily production. This "costless collar" agreement was effective beginning August 1, 2009 and had a $60.00 per barrel floor and $81.50 per barrel cap on a volume of 9,500 barrels per month during the period from August 1, 2009 through December 31, 2010, and 7,375 barrels per month from January 1 through July 31, 2011. The prices referenced in this agreement were WTI NYMEX. While the agreement was based on WTI NYMEX prices, the Company received a price based on Kansas Common plus bonus, which resulted in a price approximately $7 per barrel less than current WTI NYMEX prices. This agreement expired on August 1, 2011 and is no longer in effect as of the date of this Report.

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

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

Interest Rate Risk

At September 30, 2011, the Company had debt outstanding of $11.1 million including, as of that date, $10.9 million owed on its credit facility with F&M Bank. The interest rate on the credit facility was variable at a rate equal to the greater of prime plus 0.25% or 5.25% per annum. The Company's debt owed to other parties of $0.2 million has fixed interest rates ranging from 5.5% to 8.25%.

The annual impact on interest expense and the Company's cash flows of a 10% increase in the interest rate on the credit facility would be approximately $0.06 million assuming borrowed amounts under the credit facility remained at the same amount owed as of September 30, 2011. The Company did not have any open derivative contracts relating to interest rates at September 30, 2011 or 2010.

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 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

The Company's Chief Executive Officer and Chief Financial Officer, and other members of management have evaluated the effectiveness of the Company's disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)). Based on such evaluation, the Company's Chief Executive Officer and Chief Financial Officer have concluded that the Company's disclosure controls and procedures, as of the end of the period covered by this Report, were adequate and effective to provide reasonable assurance that information required to be disclosed by the Company in reports that it files or submits under the Exchange Act, is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms. 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.

Changes in Internal Controls

During the period covered by this Report, there have been no changes to the Company's system of internal controls over financial reporting that have materially affected, or are 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.

PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

None.

ITEM 1A. RISK FACTORS

Refer to Item 1A Risk Factors in the Company’s Report on Form 10-K for the year ended December 31, 2010 filed on March 31, 2011 which is incorporated by this reference.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULT UPON SENIOR SECURITIES

None.

ITEM 4. (REMOVED AND RESERVED)

ITEM 5. OTHER INFORMATION

None

ITEM 6. EXHIBITS

The following exhibits are filed with this report:

31.1 Certification of the Chief Executive Officer, pursuant to Exchange Act Rule, Rule 13a-14a/15d-14a.

31.2 Certification of the Chief Financial Officer, pursuant Exchange Act Rule, Rule 13a-14a/15d-14a.

32.1 Certification of the 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 the Chief Financial Officer, pursuant to 18 U.S.C Section 1350 as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002.

101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Calculation Linkbase Document
101.DEF	XBRL Taxonomy Definition Linkbase Document
101.LAB	XBRL Taxonomy Label Linkbase Document
101.PRE	XBRLTaxonomy Presentation Linkbase Document

SIGNATURES

Pursuant to the requirements of the Securities and Exchange Act of 1934, the Registrant duly caused this report to be signed on its behalf by the undersigned hereto duly authorized.

Dated: November 14, 2011

TENGASCO, INC.

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

By: s/Michael J. Rugen
Michael J. Rugen
Chief Financial Officer

Exhibit 31.1 CERTIFICATION

I, Jeffrey R. Bailey, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Tengasco, Inc. for the quarter ended September 30, 2011.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-(f) for the registrant and we have:

(a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

(c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The Registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: November 14, 2011

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

I, Michael Rugen, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Tengasco, Inc. for the quarter September 30, 2011.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-(f) for the registrant and we have:

(a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

(c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The Registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: November 14, 2011
By: s/ Michael J. Rugen
Michael J. Rugen
Chief Financial Officer

Exhibit 32.1
CERTIFICATION

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 I hereby certify that:

I have reviewed the Quarterly Report on Form 10-Q for the quarter ended September 30, 2011.

To the best of my knowledge this Quarterly Report on Form 10-Q (i) fully complies with the requirements of section 13(a) or 15(d) of the Securities and Exchange Act of 1934 (15 U.S.C. 78m (a) or 78o (d)); and, (ii) the information contained in this Report fairly present, in all material respects, the financial condition and results of operations of Tengasco, Inc. and its subsidiaries during the period covered by this report.

Dated: November 14, 2011

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

Exhibit 32.2
CERTIFICATION

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 I hereby certify that:

I have reviewed the Quarterly Report on Form 10-Q for the quarter ended September 30, 2011.

To the best of my knowledge this Quarterly Report on Form 10-Q (i) fully complies with the requirements of section 13(a) or 15(d) of the Securities and Exchange Act of 1934 (15 U.S.C. 78m (a) or 78o (d)); and, (ii) the information contained in this Report fairly present, in all material respects, the financial condition and results of operations of Tengasco, Inc. and its subsidiaries during the period covered by this report.

Dated: November 14, 2011

By: s/ Michael J. Rugen
Michael J. Rugen
Chief Financial Officer