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 June 30, 2012

Commission File No. 1-15555

Tengasco, Inc.

(Exact name of registrant 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)

(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (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 (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). [X] Yes [ ] No

Indicate by check mark 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: 60,787,413 common shares at August 6, 2012.

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Tengasco, Inc. and Subsidiaries
Condensed Consolidated Balance Sheets
(unaudited)

(in thousands, except share data)

	June 30, 2012	December 31, 2011
Assets		
Current		
Cash and cash equivalents	$ 60	$ 68
Accounts receivable	1,954	1,579
Accounts receivable – related party	166	265
Inventory	1,327	823
Deferred tax asset-current	164	164
Commodity derivative asset-current	37	142
Other current assets	104	79
Total current assets	3,812	3,120
Restricted cash	121	121
Loan fees, net	83	82
Oil and gas properties, net (*full cost accounting method*)	25,513	20,206
Pipeline facilities, net	6,778	6,865
Methane project, net	4,487	5,102
Other property and equipment, net	487	426
Deferred tax asset-noncurrent	9,124	10,077
Total assets	$ 50,405	$ 45,999

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

Tengasco, Inc. and Subsidiaries
Condensed Consolidated Balance Sheets
(unaudited)

(in thousands, except share data)

	June 30, 2012	December 31, 2011
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable – trade	$ 1,235	$ 1,203
Accounts payable – other	166	265
Accrued liabilities	592	710
Current maturities of long-term debt	131	103
Total current liabilities	2,124	2,281
Asset retirement obligation	2,045	1,927
Long term debt, less current maturities	14,124	11,694
Total liabilities	18,293	15,902
Stockholders' equity		
Common stock, $.001 par value, authorized 100,000,000 shares, 60,787,413 and 60,737,413 shares issued and outstanding	61	61
Additional paid–in capital	55,650	55,595
Accumulated deficit	(23,599)	(25,559)
Total stockholders' equity	32,112	30,097
Total liabilities and stockholders' equity	$ 50,405	$ 45,999

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 June 30		For the Six Months Ended June 30	
	2012	2011	2012	2011
Revenues	$ 5,230	$ 4,785	$ 10,196	$ 8,447
Cost and expenses				
Production costs and taxes	2,006	1,678	3,768	3,202
Depreciation, depletion, and amortization	904	666	1,657	1,237
General and administrative	600	719	1,359	1,242
Total cost and expenses	3,510	3,063	6,784	5,681
Net income from operations	1,720	1,722	3,412	2,766
Other income (expense)				
Interest expense	(206)	(164)	(394)	(309)
Gain (loss) on derivatives	15	60	(105)	(306)
Gain on sale of assets	33	8	67	11
Total other income (expenses)	(158)	(96)	(432)	(604)
Income before income tax	1,562	1,626	2,980	2,162
Income tax expense	(475)	(649)	(1,020)	(831)
Net income	$ 1,087	$ 977	$ 1,960	$ 1,331
Net income per share				
Basic and diluted	$ 0.02	$ 0.02	$ 0.03	$ 0.02
Shares used in computing earnings per share				
Basic	60,763,237	60,687,413	60,750,325	60,687,413
Diluted	61,214,257	60,761,140	61,236,066	60,761,881

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	Paid in Capital	Accumulated Deficit	Total
Balance, December 31, 2011	60,737,413	$ 61	$ 55,595	$ (25,559)	$ 30,097
Net income	-	-	-	1,960	1,960
Option and compensation expense	-	-	27	-	27
Common stock issued for exercise of options	50,000	-	28	-	28
Balance, June 30, 2012	60,787,413	$ 61	$ 55,650	$ (23,599)	$ 32,112

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the six months ended June 30 2012	2011
Operating activities		
Net income	$ 1,960	$ 1,331
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, and amortization	1,657	1,237
Amortization of loan fees-interest expense	29	38
Accretion on asset retirement obligation	67	51
Gain on sale of assets	(67)	(11)
Compensation and services paid in stock options and stock	27	85
Deferred tax expense	953	823
Loss on derivatives	105	306
Changes in assets and liabilities:		
Accounts receivable	(375)	(18)
Accounts receivable – related party	99	288
Inventory	(504)	(115)
Other assets	(25)	(69)
Accounts payable-trade	243	179
Accounts payable-other	(99)	(288)
Accrued liabilities	(118)	(28)
Settlement on asset retirement obligation	(41)	(66)
Net cash provided by operating activities	3,911	3,743
Investing activities		
Net additions to oil and gas properties	(6,792)	(3,483)
Net additions to methane project	(459)	(512)
Section 1603 payment- methane facilities	1,000	-
Net additions to other property and equipment	(15)	(41)
Proceeds from sale of other property and equipment	16	
Derivative costs and settlements	-	(1,119)
Net cash used in investing activities	(6,250)	(5,155)
Financing activities		
Repayments of borrowings	(76)	(96)
Net proceeds from borrowings	2,409	1,516
Loan fees	(30)	(60)
Proceeds from exercise of options	28	-
Net cash provided by financing activities	2,331	1,360
Net change in cash and cash equivalents	(8)	(52)
Cash and cash equivalents, beginning of period	68	141
Cash and cash equivalents, end of period	$ 60	$ 89
Supplemental cash flow information:		
Cash interest payments	$ 365	$ 271
Supplemental non-cash investing and financing activities:		
Financed company vehicles	$ 127	$ 128
Asset retirement obligations capitalized	$ 92	$ 32
Accrued capital expenditures included in accounts payable	$ 480	$ 123

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 exploration and production is the Swan Creek Field in Tennessee.

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

The Company's wholly-owned subsidiary, Manufactured Methane Corporation ("MMC") operates treatment and delivery facilities using the latest developments in available treatment technologies for the extraction of methane gas from nonconventional sources for delivery through the 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 six months ended June 30, 2012 are not necessarily indicative of the results that may be expected for the year ended December 31, 2012. 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, 2011.

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

Revenue Recognition

Revenues are recognized based on actual volumes of oil and gas sold to purchasers at a fixed or determinable price, when delivery has occurred and title has transferred, and collectability is reasonably assured. Crude oil is stored and at the time of delivery to the purchasers, revenues are recognized. Natural gas meters are placed at the customer's location and usage is billed each month. There were no material natural gas imbalances at June 30, 2012.

Cash and Cash Equivalents

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

Restricted Cash

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

Inventory

Inventory consists of crude oil in tanks and equipment and materials to be used in its Kansas operations. Inventory is carried at lower of cost or market value. At June 30, 2012 and December 31, 2011, inventory consisted of the following (in thousands):

	June 30, 2012	**December 31, 2011**
Oil	$ 482	$ 679
Equipment and materials	845	144
	$ 1,327	$ 823

Full Cost Method of Accounting

The Company follows the full cost method of accounting for oil and gas property acquisition, exploration, and development activities. Under this method, all costs incurred in connection with acquisition, exploration and development of oil and gas reserves are capitalized. Capitalized costs include lease acquisitions, seismic surveys, drilling, completion, and estimated asset retirement costs. The capitalized costs of oil and gas properties, plus estimated future development costs relating to proved reserves and estimated asset retirement costs, which are not already included net of estimated salvage value, are amortized on the unit-of-production method based on total proved reserves. The Company has determined its reserves based upon reserve reports provided by LaRoche Petroleum Consultants Ltd. in 2011, 2010, and 2009. The costs of unproved properties are excluded from amortization until the properties are evaluated, subject to an annual assessment of whether impairment has occurred. The Company had $0.3 million in unevaluated properties as of June 30, 2012 and December 31, 2011. Proceeds from the sale of oil and gas properties are accounted for as reductions to capitalized costs unless such sales cause a significant change in the relationship between costs and the estimated value of proved reserves, in which case a gain or loss is recognized.

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

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 bases of assets and liabilities, using currently enacted federal and state income tax rates. In addition, deferred tax accounts must be adjusted to reflect new rates if enacted into law. Temporary differences result principally from federal and state net operating loss carryforwards, differences in oil and gas property values resulting from a 2008 ceiling test write down, differences in pipeline values resulting from a 2010 impairment, and differences in methods of reporting depreciation and amortization. Realization of deferred tax assets is contingent on the generation of future taxable income. Management routinely assesses the ability to realize our deferred tax assets and reduces such assets by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be recognized.

At December 31, 2011, federal net operating loss carryforwards amounted to approximately $16.2 million which expire between 2021 and 2029. The total deferred tax asset was $9.3 million and $10.2 million at June 30, 2012 and December 31, 2011, respectively.

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

Although management considers neither a valuation allowance nor a loss contingency as of June 30, 2012 and December 31, 2011 necessary, material changes in these amounts may occur in the future based on tax audits and changes in legislation.

During the quarter ended June 30, 2012, the Company received a payment in the amount of approximately $1.0 million for a cash payment in lieu of tax credits relating to the MMC facility. This payment resulted in a $0.2 million deferred tax asset which was recognized in the second quarter 2012. The tax effect of recognizing the deferred tax asset has been recorded in "Income tax expense" in the Consolidated Statements of Operations. A further description of this payment is found in Note 9 Methane Project.

(3) Earnings per Share

We report basic earnings per common share, which excludes the effect of potentially dilutive securities, and diluted earnings per common share which includes the effect of all potentially dilutive securities unless their impact is anti-dilutive. The following are reconciliations of the numerators and denominators of our basic and diluted earnings per share:

	For the three months ended		For the six months ended	
	June 30, 2012	June 30, 2011	June 30, 2012	June 30, 2011
Income (numerator):				
Net income (in thousands)	$ 1,087	$ 977	$ 1,960	$ 1,331
Weighted average shares (denominator):				
Weighted average shares - basic	60,763,237	60,687,413	60,750,325	60,687,413
Dilution effect of share-based compensation, treasury method	451,020	73,727	485,741	74,468
Weighted average shares - dilutive	61,214,257	60,761,140	61,236,066	60,761,881
Earnings per share:				
Basic	$ 0.02	$ 0.02	$ 0.03	$ 0.02
Dilutive	$ 0.02	$ 0.02	$ 0.03	$ 0.02

(4) Recent Accounting Pronouncements

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

(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., 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 40 barrels per day in total. Hoactzin paid a total of $3.85 million (the “Purchase Price”) for its interest in the Ten Well Program resulting in the Payout Point being determined as $5.2 million. The amount paid by Hoactzin for its interest in the Program wells exceeded the Company’s actual drilling costs of approximately $2.8 million for the ten wells by more than $1 million.

Under the terms of the Company’s agreement with Hoactzin, reaching the Payout Point may be accelerated by operation of a second agreement by which Hoactzin will apply 75% of the net profits it may receive from a methane extraction project discussed below developed by the Company’s wholly-owned subsidiary, Manufactured Methane Corporation (“MMC”), to the Payout Point. However, as discussed below, although the Methane Project has been placed into operation, no Methane Project net profits have been generated or paid to Hoactzin through June 30, 2012.

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 June 30, 2012, 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 theagreement, have been generated from project startup in April, 2009 through June 30, 2012 for payment to Hoactzin under the net profits interest conveyed. When the Payout Point is reached from either the revenues from the wells drilled in the Ten Well Program or Hoactzin's share of the net profits from the Methane Project or a combination thereof, Hoactzin's net profits interest in the Methane Project will decrease to a 7.5% net profits interest.

On September 17, 2007, the Company also entered into a third simultaneous agreement with Hoactzin providing that if the Program and the Methane Project interest in combination failed to return net revenues to Hoactzin equal to 25% of the Purchase Price it paid for its interest in the Ten Well Program by December 31, 2009, then Hoactzin would have an option to exchange up to 20% of its net profits interest in the Methane Project for convertible preferred stock to be issued by the Company with a liquidation value equal to 20% of the Purchase Price less the net proceeds received at the time of any exchange. By June 30, 2012, the amount of net revenues received by Hoactzin from the Ten Well Program has reduced the Company's obligation to Hoactzin for the amount of the funds it had advanced for the Purchase Price from $3.85 million to zero, thereby reaching the purchase price and therefore no preferred stock will ever be issued to Hoactzin.

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

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

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

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

As operator, the Company has routinely contracted in its name for goods and services with vendors in connection with its operation of the Hoactzin properties. In practice, Hoactzin pays directly these invoices for goods and services that are contracted in the Company's name. During late 2009 and early 2010, Hoactzin undertook several significant operations, for which the Company contracted in the ordinary course. As a result of the operations performed in late 2009 and early 2010, Hoactzin currently has past due balances to several vendors, a portion of which are included on the Company's balance sheet. Payables related to these and ongoing operations remained outstanding at June 30, 2012 and December 31, 2011 in the amounts of $0.166 million and $0.265 million, respectively. The Company has recorded the Hoactzin-related payables and the corresponding receivable from Hoactzin as of June 30, 2012 and December 31, 2011 in its Consolidated Balance Sheets under "Accounts payable – other" and "Accounts receivable – related party". No Tengasco funds have been advanced by Tengasco to pay any obligations of Hoactzin. No borrowing capability of Tengasco has been used by the Company in connection with its obligations under the Management Agreement. The Management Agreement terminates at the earlier of the date of sale, if any, by Hoactzin of its managed properties, or December 2012.

(6) Oil and Gas Properties

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

	June 30, 2012	December 31, 2011
Oil and gas properties, at cost	$ 42,695	$ 36,002
Unevaluated properties	268	268
Accumulated depletion	(17,450)	(16,064)
Oil and gas properties, net	$ 25,513	$ 20,206

The Company recorded $1.4 million in depletion expense for the first six months of 2012 and $1.0 million for the first six months of 2011.

(7) Asset Retirement Obligation

Our asset retirement obligations represent the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives in accordance with applicable laws. The following table summarizes the Company's Asset Retirement Obligation transactions for the six months ended June 30, 2012 *(in thousands):*

Balance December 31, 2011	$ 1,927
Accretion expense	67
Liabilities incurred	92
Liabilities settled	(41)
Balance June 30, 2012	$ 2,045

(8) Long-Term Debt

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

	June 30, 2012	December 31, 2011
Note payable to a financial institution, with interest only payment until maturity.	$ 13,940	$ 11,531
Installment notes bearing interest at the rate of 5.5% to 8.25% per annum collateralized by vehicles with monthly payments including interest, insurance and maintenance of approximately $20,000	315	266
Total long-term debt	14,255	11,797
Less current maturities	(131)	(103)
Long-term debt, less current maturities	$ 14,124	$ 11,694

At June 30, 2012, the Company had a revolving credit facility with F&M Bank & Trust Company N.A. of Dallas, Texas ("F&M Bank"). Under the credit facility, loans and letters of credit are available to the Company on a revolving basis in an amount outstanding not to exceed the lesser of $40 million or the Company's borrowing base in effect from time to time. The credit facility is secured by substantially all of the Company's producing and non-producing oil and gas properties and pipeline and the Company's Methane Project assets. The credit facility includes certain covenants with which the Company is required to comply. These covenants include leverage, interest coverage, minimum liquidity, and general and administrative coverage ratios. At June 30, 2012 and December 31, 2011, the Company was in compliance with all covenants.

On March 14, 2012, the Company's senior credit facility with F&M Bank after F&M Bank's semiannual review of the Company's currently owned producing properties was amended to increase the Company's borrowing base from $20 million to $23 million and extend the term of the facility to January 27, 2014. The interest rate remained the greater of prime plus 0.25% or 5.25% per annum (rate at June 30, 2012 was 5.25%).

The total borrowing by the Company under the F&M Bank credit facility at June 30, 2012 and December 31, 2011 was $ 13.9 million and $11.5 million, respectively. The next borrowing base review will occur in August 2012.

(9) Methane Project

The methane facilities were placed into service on April 1, 2009. The methane facilities are being depreciated over the estimated useful life of approximately 33 years. This useful life is based on estimated landfill closure date of December 2041. The Company recorded depreciation expense of $0.05 million for the six months ended June 30, 2012 and 2011.

In June 2012, the Company received a payment in the amount of approximately $1.0 million from the United States Department of the Treasury for a cash payment in lieu of tax credits relating to the methane facilities. The payment to the Company was authorized under Section 1603 of Division B of the American Recovery and Reinvestment Act of 2009. The grant amount was calculated pursuant to provisions applicable to a "landfill gas project," defined in this statute as a project generating electricity from landfill gas. The Company may not take investment tax credits for this facility as a result of accepting the cash payment, and is subject to annual reporting of the status of the project and recapture of all or a portion of the payment in the event the project were to be assigned to an ineligible nonprofit or governmental entity, during the five year period following the date of the award. The Company does not anticipate that the payment will be subject to recapture. Pursuant to the terms of the implementing federal regulations, the cash payment awarded is not treated as taxable income, but does reduce the taxable basis of the project by half of the grant amount. However, the book carrying amount of the property is reduced by the full amount of the payment.

(10) Fair Value Measurements

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

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

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

Level 3 – Unobservable inputs that are supported by little or no market activity, generally requiring a significant amount of judgment by management. The assets or liabilities fair value measurement level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. Valuation techniques used need to maximize the use of observable inputs and minimize the use of unobservable inputs. Following is a description of the valuation methodologies used for assets measured at fair value.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. Further, 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 Company's commodity derivative instruments are recorded at fair value on a recurring basis in our balance sheet with changes in fair value recorded in our income statement. The following table sets forth by level, within the fair value hierarchy, the Company's assets and liabilities at fair value on a recurring basis as of June 30, 2012 and December 31, 2011. During 2012 and 2011, there were no changes in the fair value level classification. (*in thousands*)

June 30, 2012	**Level 1**		**Level 2**		**Level 3**
Derivative assets	$ -		$ 37		$ -
Total assets at fair value	$ -		$ 37		$ -

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

The fair value of the Company's commodity derivative instruments are estimated using a pricing model which has various inputs including forward price curves, volatilities, interest rates and contract terms. Contract terms related to the Company's commodity derivative instruments are defined in footnote 11 Derivatives.

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

Nonfinancial assets and liabilities are measured at fair value on a nonrecurring basis upon impairment, however, we have no material assets and liabilities that are reported at fair value on a nonrecurring basis in our balance sheet.

The carrying amounts of other financial instruments including cash and cash equivalents, accounts receivable, account payables, accrued liabilities and long term debt in our balance sheet approximates fair value as of June 30, 2012 and December 31, 2011.

(11) Derivatives

On July 28, 2009, the Company entered into a two-year agreement on crude oil pricing. This "costless collar" agreement was effective August 1, 2009 through July 31, 2011 and had a $60.00 per barrel floor and $81.50 per barrel cap on a volume of 9,500 barrels per month during the period from August 1, 2009 through December 31, 2010, and 7,375 barrels per month from January 1, 2011 through July 31, 2011. The prices referenced in this agreement were WTI NYMEX. While the agreement was based on WTI NYMEX prices, the Company receives a price based on Kansas Common plus bonus, which results in a price approximately $7 per barrel less than current WTI NYMEX prices. As of August 1, 2011, the “costless collar” agreement had expired.

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

As of June 30, 2012, the Company’s open forward positions were as follows (fair value is based on methodology described in Note 10 Fair Value Measurements):

Period	Monthly Volume	Total Volume	Floor/Cap NYMEX	Fair Value at June 30, 2012
	Oil (Bbls)	Oil (Bbls)	$ per Bbl	(in thousands)
3rd Qtr 2012	10,000	30,000	$65.00-N/A	$ 5
4th Qtr 2012	10,000	30,000	$65.00-N/A	$ 32
			Current Asset	$ 37

As of December 31, 2011, the Company’s open forward positions were as follows (fair value is based on methodology described in Note 10 Fair Value Measurement):

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

The Company records changes in the unrealized derivative asset or liability as a “Loss on derivatives” in the Consolidated Statements of Operations. The Company recorded a $(0.105) million unrealized loss and a $0.439 million unrealized gain for the six months ended June 30, 2012 and 2011, respectively. During the six months ended June 30, 2011, the Company made settlement payments of $(0.745) million. The Company did not make any settlement payments for the six months ended June 30, 2012. This realized loss was recorded as a "Loss on derivatives" in the Consolidated Statements of Operations.

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

Results of Operations and Financial Condition

During the first six months of 2012, the Company sold 133 MBbl of oil from its Kansas wells. Of the 133 MBbl, 106 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 six months of 2012 of 106 MBbl of oil compares to 88 MBbl net to the Company's interest in the first six months of 2011. This 18 MBbl increase was due primarily to increased sales volumes on the Coddington, DeYoung, Hilgers "B", Liebenau, McElhaney "A", Veverka "A" and various other leases resulting from the 2011 and 2012 drilling and polymer programs. The Company's net revenue from the Kansas properties was $9.6 million in the first six months of 2012 compared to $8.1 million in 2011. This increase in net revenue was due primarily to $1.6 million increase related to the 18 MBbl increase in sales volumes, partially offset by a $(0.1) million decrease related to the $(1.00) per barrel decrease in the average Kansas oil price from $91.57 per barrel in 2011 to $90.57 per barrel in 2012. For the first six months of 2012 and 2011, the Company's sales included $0.2 million from Swan Creek, and MMC revenues of $0.4 million and $0.1 million for 2012 and 2011, respectively.

Comparison of the Quarters Ended June 30, 2012 and 2011

The Company recognized $5.23 million in revenues during the second quarter of 2012 compared to $4.79 million in the second quarter of 2011. The increase in 2012 revenues was primarily due to a $0.9 million increase related to a 9.4 MBbl increase in sales volumes partially offset by a $(0.55) million decrease related to a $(9.56) per barrel decrease in average Kansas oil prices. Kansas oil prices in the second quarter of 2012 averaged $85.90 per barrel compared to $95.46 per barrel in the second quarter of 2011. In addition, MMC revenues increased $0.14 million from $0.06 million in the second quarter 2011 to $0.2 million in the second quarter 2012. The Company realized net income attributable to common shareholders of $1.1 million or $0.02 per share of common stock during the second quarter of 2012, compared to a net income in the second quarter of 2011 to common shareholders of $1.0 million or $0.02 per share of common stock. In the second quarter of 2012 and 2011, the Company had income from operations of $1.7 million. Although revenues increased $0.44 million, this increase was offset by a $0.33 million increase in operating cost and a $0.24 million increase in depreciation, depletion, and amortization. These cost increases were partially offset by a $0.12 decrease in general and administrative costs.

Production costs and taxes in the second quarter of 2012 increased $0.33 million to $2.01 million from $1.68 million in the second quarter of 2011. This increase was primarily due to $0.15 million increase related to a change in oil inventory, $0.1 million increase in MMC costs, and increases in miscellaneous Kansas field operating costs.

Depreciation, depletion, and amortization expense was $0.904 million and $0.666 million for the second quarters of 2012 and 2011, respectively. This increase was primarily due to increased oil volumes as well as an increase in the oil and gas depletion rate.

General and administrative costs decreased $0.12 million from $0.72 million for the second quarter of 2011 to $0.6 million for the second quarter of 2012.

During the second quarter of 2012, the Company recorded a $0.015 million non-cash unrealized gain on derivatives compared to a $0.53 million non-cash unrealized gain on derivatives, a $(0.47) million realized loss on derivatives resulting from settlement payments made to Macquarie recorded during the second quarter of 2011. Interest expense was $0.21 million and $0.16 million for the second quarters of 2012 and 2011, respectively.

Comparison of the Six Months Ended June 30, 2012 and 2011.

The Company recognized $10.2 million in revenues during the first six months of 2012 compared to $8.4 million in the first six months of 2011. The increase in revenues was primarily due to a $1.6 million increase related to an 18 MBbl increase in oil sales volumes during the first six months of 2012, partially offset by a $(0.1) million decrease related to a $(1.00) per barrel decrease in average oil prices from $91.57 during the first six months of 2011 to $90.57 during the first six months of 2012. In addition MMC revenues increased $0.3 million from $0.1 million during the first six months for 2011 to $0.4 million during the first six months of 2012. Electric revenues contributed $0.24 million of this increase as a result of installation of an electric generator in January 2012 at the methane facilities. The Company realized net income attributable to common shareholders of $2.0 million or $0.03 per share of common stock during the first six months of 2012 compared to a net income in the first six months of 2011 to common shareholders of $1.3 million or $0.02 per share of common stock. During the first six months of 2012, the Company had income from operations of $3.4 million compared to income from operations of $2.8 million during the first six months of 2011. 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 MMC revenues, partially offset by a $1.1 million increase in costs and expenses.

Production cost and taxes in the first six months of 2012 increased $0.6 million from $3.2 million in the first six months of 2011 to $3.8 million in the first six months of 2012. This increase resulted primarily from a $0.2 million increase related to a change in oil inventory, $0.1 increase in MMC costs and increases in miscellaneous Kansas field operating costs.

Depletion, depreciation, and amortization expense increased $0.42 million for the first six months of 2012, from $1.24 million in the first six months of 2011 to $1.66 million in the first six months of 2011. This increase was primarily due to increased oil volumes as well as an increase in the oil and gas depletion rate.

General and administrative costs increased $0.12 million for the first six months of 2012 from $1.24 million for the first six months of 2011 to $1.36 million during the first six months of 2012.

During the first six months of 2012, the Company recorded a $(0.105) million non-cash unrealized loss on derivatives compared to an $0.439 million non-cash unrealized gain on derivatives, a $(0.745) million realized loss on derivatives resulting from settlement payments made to Macquarie, in the first six months of 2011. Interest expense was $0.39 million and $0.31 million for the first six months of 2012 and 2011, respectively. The increase in the interest expense was due to increased borrowings to supplement funding of material inventory purchases and the 2012 drilling program.

Liquidity and Capital Resources

At June 30, 2012, the Company had a revolving credit facility with F&M Bank & Trust Company ("F&M Bank"). Under the credit facility, loans and letters of credit are available to the Company on a revolving basis in an amount outstanding not to exceed the lesser of $40 million or the Company's borrowing base in effect from time to time. The credit facility is secured by substantially all of the Company's producing and non-producing oil and gas properties and pipeline and the Company's Methane Project assets. The credit facility includes certain covenants with which the Company is required to comply. These covenants include leverage, interest coverage, minimum liquidity, and general and administrative coverage ratios. At June 30, 2012 and December 31, 2011, the Company was in compliance with all covenants.

On March 14, 2012, the Company's senior credit facility with F&M Bank and Trust Company, N.A. of Dallas, Texas (F&M Bank") after F&M Bank's semiannual review of the Company's currently owned producing properties was amended to increase the Company's borrowing base from $20 million to $23 million and extend the term of the facility to January 27, 2014. The interest rate remained the greater of prime plus 0.25% or 5.25% per annum (rate at June 30, 2012 was 5.25%).

The total borrowing by the Company under the F&M Bank credit facility at June 30, 2012 and December 31, 2011 was $13.9 million and $11.5 million, respectively. The next borrowing base review will occur in August 2012.

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 2011 and 2012, 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 six months of the year, net cash provided by operating activities was $3.9 million in 2012 and $3.7 million in 2011. The increase of cash provided by operating activities from 2011 to 2012 was primarily due to increased revenues partially offset by increased materials and equipment inventory. Cash flow used in working capital increased $(0.7) million to $(0.8) million in 2012 from $(0.1) million used in working capital in 2011. The increase was due primarily to an increase in inventory and accounts receivable. Net cash used in investing activities was $(6.25) million in 2012 and $(5.16) million in 2011. The $(1.1) million increase in cash used in investing activities was primarily due to a $(3.3) million increase in drilling and polymer cost partially offset by a $1.1 million reduction in derivative cost and receipt of a $1.0 million payment in lieu of tax credits related to the methane facilities. This payment was authorized under section 1603 of division B of the American Recovery and Reinvestment Act of 2009. Cash flow provided by financing activities during the first six months of 2012 was $2.3 million compared to $1.4 million during the first six months of 2011. The change in financing activities was primarily due to increased borrowings in 2012 to supplement funding of drilling and polymer cost as well as materials and equipment inventory purchases.

Critical Accounting Policies

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

Revenue Recognition

Revenues are recognized based on actual volumes of oil and gas sold to purchasers at a fixed or determinable price, when delivery has occurred and title has transferred, and collectability is reasonably assured. Crude oil is stored and at the time of delivery to the purchasers, revenues are recognized. Natural gas meters are placed at the customer's location and usage is billed each month. There were no material natural gas imbalances at June 30, 2012.

Inventory

Inventory consists of crude oil in tanks and equipment and materials to be used in its Kansas operations. Inventory 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 costs incurred in connection with acquisition, exploration and development of oil and gas reserves are capitalized. Capitalized costs include lease acquisitions, seismic surveys, drilling, completion, and estimated asset retirement costs. The capitalized costs of oil and gas properties, plus estimated future development costs relating to proved reserves and estimated asset retirement costs, which are not already included net of estimated salvage value, are amortized on the unit-of-production method based on total proved reserves. The Company has determined its reserves based upon reserve reports provided by LaRoche Petroleum Consultants Ltd. in 2011, and 2010. The costs of unproved properties are excluded from amortization until the properties are evaluated, subject to an annual assessment of whether impairment has occurred. The Company has $0.3 million in unevaluated properties as of June 30, 2012. Proceeds from the sale of oil and gas properties are accounted for as reductions to capitalized costs unless such sales cause a significant change in the relationship between costs and the estimated value of proved reserves, in which case a gain or loss is recognized.

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

Oil and Gas Reserves / Depletion of Oil and Gas Properties

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

The Company’s proved oil and gas reserves as of December 31, 2011 were determined by LaRoche Petroleum Consultants, Ltd. Projecting the effects of commodity prices on production, and timing of development expenditures includes many factors beyond the

Company's control. The future estimates of net cash flows from the Company's proved reserves and their present value are based upon various assumptions about future production levels, prices, and costs that may prove to be incorrect over time. Any significant variance from assumptions could result in the actual future net cash flows being materially different from the estimates.

Asset Retirement Obligations

The Company's asset retirement obligations relate to the plugging, dismantling and removal of wells drilled to date. The Company follows the requirements of FASB ASC 410, "Asset Retirement Obligations and Environmental Obligations". Among other things, FASB ASC 410 requires entities to record a liability and corresponding increase in long-lived assets for the present value of material obligations associated with the retirement of tangible long-lived assets. Over the passage of time, accretion of the liability is recognized as an operating expense and the capitalized cost is depleted over the estimated useful life of the related asset. The Company's asset retirement obligations relate primarily to the plugging, dismantling and removal of wells drilled to date. The Company's calculation of asset retirement obligations currently uses a credit adjusted risk free rate of 5.25% and an estimated useful life of wells ranging from 30-40 years. 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 June 30, 2012, the Company's borrowing base was set at $23 million of which $13.9 million had been drawn down by the Company. The Company's next periodic borrowing base review will occur in August 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 2011 ranged from a low of $78.90 per barrel to a high of $103.12 per barrel. Gas prices realized during the same period ranged from a low of $4.03 per Mcf to a high of $7.38 per Mcf.

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

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

Under the "costless collar" agreement, no payment was made or received by the Company, as long as the settlement price was between the floor price and cap price ("within the collar"). However, if the settlement price was above the cap, the Company was required to pay the counterparty an amount equal to the excess of the settlement price over the cap times the monthly volumes hedged. If the settlement price was below the floor, the counterparty was required to pay the Company the deficit of the settlement price below the floor times the monthly volumes hedged. As of August 1 2011, the “costless collar” agreement had expired. On June 27, 2011 the Company entered into an agreement with Cargill, for the period from August 1, 2011 through December 31, 2012. The agreement provides to the Company a $65 per barrel floor on a stated quantity of 10,000 barrels per month, which is approximately half of the Company’s current production of oil. If the average price falls below $65 per barrel, then Cargill will pay to the Company the difference between $65 and the lower average price for 10,000 barrels per month in each month during when such lower average prices occur. However, unlike the “costless collar” arrangement, the Company will not have a price cap on any portion of its production volumes. The cost of the Cargill agreement to the Company, which was paid on June 27, 2011, was $2.20 per barrel per month or a total of $374,000 for the entire period of the agreement.

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

Interest Rate Risk

At June 30, 2012, the Company had debt outstanding of $14.3 million including, as of that date, $13.9 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 $0.3 million has fixed interest rates ranging from 3.9% to 7.25%.

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 $0.07 million assuming borrowed amounts under the credit facility remained at the same amount owed as of June 30, 2012. The Company did not have any open derivative contracts relating to interest rates at June 30, 2012 or 2011.

Forward-Looking Statements and Risk

Certain statements in this report, including statements of the future plans, objectives, and expected performance of the Company, are forward-looking statements that are dependent upon certain events, risks and uncertainties that may be outside the Company's control, and which 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, 2011 filed on March 29, 2012 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. MINE SAFETY DISCLOSURES

Not Applicable

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: August 14, 2012

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 June 30, 2012.

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: August 14, 2012

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 June 30, 2012.

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: August 14, 2012
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 June 30, 2012.

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: August 14, 2012

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 June 30, 2012.

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: August 14, 2012

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