TENGASCO INC
Form 10-K/A
September 13, 2005

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

REPORT ON FORM 10-K/A

(Mark one)

/X/ Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended **December 31, 2004** or

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

Commission File No. **0-20975**

TENGASCO, INC.

(Name of registrant as specified in its charter)

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

10215 Technology Drive Suite 301, Knoxville, Tennessee 3732
(Address of Principal Executive Offices) (Zip Code)

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

Securities registered pursuant to Section 12(b) of the Act: **None.**

Securities registered pursuant to Section 12(g) of the Act: **Common Stock, $.001 par value per share.**

Indicate by checkmark whether the registrant (1) filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or 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 if disclosure of delinquent filers in response to Item 405 of Regulation SK is not contained in this form and no disclosure will be contained, to the best of the registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

Indicate by checkmark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act): Yes / / No /X/

Indicate by checkmark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act): Yes **/ /** No **/X/**

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant s most recently completed second quarter (June 30, 2004 closing price $0.38): **$11,854,484**

State the number of shares outstanding of the registrant s $.001 par value common stock as of the close of business on the latest practicable date (February 1, 2005): **48,927,828**

This Amendment on Form No. 1 to Form 10-K amends our annual report for the year ended December 31, 2004 filed on March 31, 2005. There are four amendments to the Form 10-K. First, page 4 of the Form 10-K is amended to further clarify the relationship between actual production levels and proved reserves calculations in 2003 and 2004. Second, page F-6 is amended to reposition the Net Loss to be located before deducting dividends on preferred stock necessary to arrive at net loss attributable to common stockholders. This affects only the year 2003, and has no effect on any calculation of net loss to common shareholders in any year. The third amendment is made on page F-12 to include an affirmative statement that the Company has no undeveloped unproved propterties so none were excluded from the full cost pool. The fourth amendment which is at page F-15 is to include additional information concerning the percentage of revenues supplied by customers contributing more than ten percent of revenues.

Documents Incorporated By Reference: None.

2002 through 2004 due to ongoing disputes with Bank One, the Company s principal lender, and the resulting lack of available capital. That dispute was finally settled in May 2004.

After the Bank One lawsuit was resolved, the Company drilled two new wells in 2004 in the Swan Creek Field to the Knox Formation. This resulted in one producing well, the Steve Lawson #8, which is currently producing approximately 10,000 cubic feet of natural gas per day. The other well, the Hazel Sutton #3, did not result in the production of commercial volumes of gas. An attempt was made to have this well produce oil from the Trenton formation, a shallower interval, but this also proved unsuccessful. The Company does not believe it is likely that commercial quantities of oil or gas will occur from the Hazel Sutton #3 well and it is anticipated that upon final review it will be plugged.

Because the Knox formation of the Swan Creek Field has been now been more specifically defined by the accumulation of data from previously drilled wells and seismic data, the Company now believes that drilling new gas wells in the Field will not contribute to achieving any significant increase in daily gas production totals from the Field. As a result, the Company does not have any plans at the present time to drill any new gas wells in the Swan Creek Field.

Further, the Company now expects that even if new wells were drilled in the Swan Creek Field, the deliverability of natural gas from the Field will not be sufficient to satisfy the volumes deliverable under its contracts with Eastman and BAE in Kingsport, Tennessee. The Eastman contract provides that Eastman will buy a minimum of the lesser of eighty percent of that customer s daily usage or 10,000 MMBtu per day, and the BAE contract provides that BAE will buy a minimum of all of that customer s usage or 5,000 MMbtu per day after Eastman s volumes have been provided. The Company s current production from the Swan Creek field is approximately 745 MMBtu per day. The Company s contracts with these customers are only for gas produced from the Swan Creek Field. So long as that Field is not capable of supplying these volumes, the Company is not in breach or violation of these contracts. No penalty is associated with the inability of the Field to produce the volumes that the Company could deliver and buyers would be obligated to buy under its industrial contracts if the volumes were physically available from the Field. However, in the event that the Company were found to be in breach of its obligations for failure to deliver any volumes of gas that is produced from the Swan Creek Field to either of these customers, the agreements limit potential exposure to damages. Damages are limited to no more than $.40 per MMBtu for any replacement volumes that are proved in a court proceeding as having been obtained to replace volumes required to be furnished but not furnished by the Company.

The experienced decline in actual production levels from existing wells in the Swan Creek Field was expected and does not diminish either the shut-in pressure or the Company s proved producing reserves in the Swan Creek Field. The declines, however, suggest the production rates from some of the Company s wells will continue to be slower, which may result in such wells lasting longer than originally expected. Although there can be no assurance, the Company expects these natural rates of decline will be less than the decline experienced to date, and that ongoing production from existing wells will tend to stabilize near current production levels. The Company anticipates that the natural decline of production from existing wells is now predictable in the Swan Creek Field, and that proven producing reserves can be extracted primarily through existing wells; however, the total volume of proved reserves in the Swan Creek field was reduced from 16.3 BCF reported in 2003 to 6.7 BCF in 2004, a reduction of 41%.

In 2003 management had obtained state regulatory approval for drilling of infield wells in the Swan Creek field at increased density of wells. Management expected that an increased density of wells within the existing Swan Creek field would result in additional reserves and reported those reserves as proven in accordance with reservoir engineering standards. In 2004, the Company drilled and tested two new infield developmental wells in the Swan Creek field as discussed above. Contrary to the expectations for additional infield developmental wells, drilling and testing results of the first two wells indicated that the current wells in production in the Swan Creek Field would be capable of and would likely produce all the remaining reserves, in that Field and that only limited additional gas reserves could be added with additional infield developmental drilling. Accordingly, the proven reserves associated with the increased number of infield developmental wells in 2003 were not included in the proven reserves reported by the Company in 2004, resulting in a volume change from 16.3 BCF in 2003 to 6.7 BCF in 2004 of total proven gas reserves in the Swan Creek Field. See Note 18 to the Consolidated Financial Statements. This change was almost entirely related to undeveloped locations that management now believes do not have a likelihood of being drilled in the future, and was not related in any manner to the natural decline in production experienced in 2004 from existing wells in the Swan Creek Field as discussed above.

4

Natural gas production from the Swan Creek Field during 2004 averaged 611 thousand cubic feet per day compared to 1.053 million cubic feet per day in 2003.

During 2004, the Company had 22 producing gas wells and 5 producing oil wells in the Swan Creek Field. Miller Petroleum, Inc. and others had a participating interest in 7 of these wells. See, Item 2 Description of Property Property Location, Facilities, Size and Nature of Ownership. In total, the Company has completed 47 wells in the Swan Creek Field. The majority of these gas wells were drilled prior to the completion of the pipeline system so only test data was available prior to full production. Of the completed wells, 12 are not producing commercial quantities of hydrocarbons and will not be tied in to the Company s pipeline since the expense of connection is not justified in view of the expected volumes to be produced.

2. The Kansas Properties

In 1998, the Company acquired the Kansas Properties, which presently include 129 producing oil wells and 51 producing gas wells in the vicinity of Hays, Kansas and a 50 mile gas gathering system. The Company also acquired 37 other wells, which now serve as saltwater disposal wells in the vicinity of Hays, Kansas. These saltwater disposal wells reduce operating costs by eliminating the need for transportation out of the area of the salt water produced in the oil production process. The aggregate production for the Kansas Properties in 2004 was 716 Mcf of gas and 326 barrels of oil per day. Revenue for the Kansas Properties was approximately $383,909 per month in 2004. The Company employs a full time geologist in Kansas to oversee operations of the Kansas Properties.

In 2004, the Company drilled one new well in Kansas, the Lewis No. 3 Well. This well was drilled to the Arbuckle formation, and is currently producing 39 barrels of oil per day. In December 2004, the Company commenced a lease acquisition program in Kansas and as of the date of this report, has increased its lease position from 32,158 acres to 42,895 acres by acquiring oil and gas leases in an area near its previous lease holdings where the Company believes there is a likelihood of additional oil production. This newly acquired acreage is largely undrilled, and the Company believes that current seismic exploration technology will enable the Company to establish additional oil production by efficient location of new wells to be drilled by the Company. The Company intends to continue to acquire additional leases in the area of its existing wells.

In February and March 2005, the Company began drilling the first two wells of an eight-well drilling program in Kansas (the Drilling Program or the Program). The Program was offered to the holders of the Company s Series A 8% Cumulative Convertible Preferred

Tengasco, Inc. and Subsidiaries

Consolidated Statements of Loss

Years ended December 31,	**2004**	**2003**	**2002**
Revenues and other income			
Oil and gas revenues	$ 6,013,374	$ 6,040,872	$ 5,437,723
Pipeline transportation revenues	92,599	163,393	259,677
Interest Income	3,501	985	3,078
Total revenues and other income	6,109,474	6,205,250	5,700,478
Costs and expenses			
Production costs and taxes	3,364,429	3,412,201	3,094,731
Depreciation, depletion and amortization (Notes 4, 5 and 6)	2,067,566	2,308,007	2,413,597
General and administrative	1,177,183	1,486,280	1,868,141
Interest expense (Notes 9, 10 and 13)	1,367,180	1,120,738	578,039
Public relations	35,347	31,183	193,229
Professional fees	779,180	549,503	707,296
Loss on impairment of long-lived asset	-	495,000	-
Loss on sale of equipment, net	107,744	-	-
Total costs and expenses	8,898,629	9,402,912	8,855,033
Operating loss	(2,789,155)	(3,197,662)	(3,154,555)
Gain from extinguishment of debt (Note 16)	336,820	-	-
Gain on Preferred Stock (Note 9)	458,310	-	-
Net loss before Cumulative effects of a changes in accounting principle	(1,994,025)	(3,197,662)	(3,154,555)
Cumulative effect of a change in accounting principle (Note 10)	-	(351,204)	-
Cumulative effect of a change in accounting principle (Note 9)	-	365,675	-
Net loss	(1,994,025)	(3,183,191)	(3,154,555)
Dividends on preferred stock (Note 9)	-	(268,389)	(506,789)
Net loss attributable to common stockholders	$ (1,994,025)	$ (3,451,580)	$ (3,661,344)
Net loss attributable to common stockholders per shares			
Basic and diluted:			
Net loss attributable to common stockholders before cumulative effects of a changes in accounting principle	$ (0.05)	$ (0.29)	$ (0.33)
	-	(0.03)	-

Years ended December 31,	**2004**	**2003**	**2002**
Cumulative effect of a change in accounting principle (Note 10)			
Cumulative effect of a change in accounting principle (Note 9)		0.03	-
Total	$ (0.05)	$ (0.29)	$ (0.33)
Weighted average shares outstanding	40,855,972	11,956,135	11,062,436

F-6

Cash and Cash Equivalents

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

Investment Securities

Investment securities available for sale are reported at fair value, with unrealized gains and losses reported as a separate component of stockholders equity, net of the related tax effects. The Company s available for sale securities were transferred as part of a lawsuit settlement in 2004. The Company recognized a realized loss of $150,000 as a result of the transfer. See Note 15.

Inventory

Inventory consists primarily of crude oil in tanks and is carried at market value.

Oil and Gas Properties

The Company follows the full cost method of accounting for oil and gas property acquisition, exploration and development activities. Under this method, all productive and nonproductive costs incurred in connection with the acquisition of, exploration for and development of oil and gas reserves for each cost center are capitalized. Capitalized costs include lease acquisitions, geological and geophysical work, delay rentals and the costs of drilling, completing equipping and closing oil and gas wells. Gains or losses are recognized only upon sales or dispositions of significant amounts of oil and gas reserves representing an entire cost center. Proceeds from all other sales or dispositions are treated as reductions to capitalized costs.

The capitalized costs of oil and gas properties, plus estimated future development costs relating to proved reserves and estimated costs of plugging and abandonment, net of estimated salvage value, are amortized on the unit-of-production method based on total proved reserves. The 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 no undeveloped unproved properties and consequently no such properties have been excluded from the full cost pool. These reserves were estimated by Ryder Scott Company, Petroleum Consultants in 2004, 2003 and 2002.

The capitalized oil and gas properties, less accumulated depreciation, depletion and amortization and related deferred income taxes, if any, are generally limited to an amount (the ceiling limitation) equal to the sum of: (a) the present value of estimated future net revenues computed by applying current prices in effect as of the balance sheet date (with

Income Taxes

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

Concentration of Credit Risk

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

The Company s primary business activities include oil and gas sales to several customers in the states of Tennessee and Kansas. The related trade receivables subject the Company to a concentration of credit risk within the oil and gas industry. The Company is presently dependent upon a small number of customers for the sale of gas from the Swan Creek Field, principally Eastman and BAE, and other industrial customers in the Kingsport area with which the Company may enter into gas sales contracts.

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

In 2002, the Company received 46.8 percent of its revenues from Customer A; 32.3 percent of its revenues from Customer B; and 13.9 percent of its revenues from Customer C.

In 2003, the Company received 45.9 percent of its revenues from Customer A; 28.1 percent of its revenues from Customer B; and 15.7 percent of its revenues from Customer C.

In 2004, the Company received 59.3 percent of its revenues from Customer A; 18.2 percent of its revenues from Customer B; and 14.4 percent of its revenues from Customer C.

In each of the years 2002 through 2004, the identity of the customers indicated above as either A, B, or C was the same from year to year, although the percentage of revenues varied slightly from year to year for that customer.

Loss per Common Share

Basic loss per share is computed by dividing loss available to common shareholders by the weighted average number of shares outstanding during each year. Shares issued during the year are weighted for the portion of the year that they were outstanding. Diluted loss per share does not differ from basic loss per share since the effect of all common stock equivalents is anti-dilutive. Basic and diluted loss per share are based upon 40,855,972 weighted average common shares outstanding for the year ended December