TENGASCO INC
Form 10-K
March 31, 2010

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

REPORT ON FORM 10-K

(Mark one)

[X} Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended December 31, 2009 or

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

Commission File No. 1-15555

TENGASCO, INC.

(name of registrant as specified in its charter)

Tennessee (state or other jurisdiction of Incorporation or organization)	87-0267438 (I.R.S. Employer Identification No.)

11121 Kingston Pike Suite, E Knoxville, TN	37934
(Address of Principal Executive Offices)	(Zip Code)

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

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

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

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

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

Indicated by check mark whether the registrant (1) filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [X] [ ] No

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 [ ] Yes [ ] No

Indicate by check mark if disclosure of delinquent filers in response to Item 405 of Regulation SK is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.[ ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. Large Accelerated Filer [ ] Accelerated Filer [ ] Non-accelerated Filer [ ] Smaller Reporting Company [ ]

(Do not check if a Smaller Reporting Company)

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter was approximately $21 million (June 30, 2009 closing price $0.56)

The number of shares outstanding of the registrant's $.001 par value common stock as of the close of business on (March 12, 2010) was 59,760,661

Documents Incorporated By Reference

The information required by Part III of the Form 10-K, to the extent not set forth herein, is incorporated herein by reference from the registrant's definitive proxy statement for the Annual Meeting of Shareholders to be held on June 21, 2010, to be filed with the Securities and Exchange Commission pursuant to Regulation 14A not later than 120 days after the close of the registrant's fiscal year.

Table of Contents

FORWARD LOOKING STATEMENTS

The information contained in this Report, in certain instances, includes forward-looking statements within the meaning of applicable securities laws. Forward-looking statements include statements regarding the Company's "expectations," "anticipations," "intentions," "beliefs," or "strategies" or any similar word or phrase regarding t future. Forward-looking statements also include statements regarding revenue margins, expenses, and earnings analysis for 2009 and thereafter; oil and gas prices; exploration activities; development expenditures; costs of regulatory compliance; environmental matters; technological developments; future products or product development; the Company's products and distribution development strategies; potential acquisitions or strategic alliances; liquidity and anticipated cash needs and availability; prospects for success of capital raising activities; prospects or the market for or price of the Company's common stock; and control of the Company. All forward-looking statements are based on information available to the Company as of the date hereof, and the Company assumes no obligation to update any such forward-looking statement. The Company's actual results could differ materially from the forward-looking statements. Among the factors that could cause results to differ materially are the factors discussed in "Risk Factors" below in Item 1A of this Report.

Projecting the effects of commodity prices, which in the past year have been extremely volatile, on production and timing of development expenditures includes many factors beyond the Company's control. The future estimates of net cash flows from the Company's proved reserves and their present value are based upon various assumptions about future production levels, prices, and costs that may prove to be incorrect over time. Any significant variance from assumptions could result in the actual future net cash flows being materially different from the estimates.

GLOSSARY OF OIL AND GAS TERMS

The following are abbreviations and definitions of certain terms commonly used in the oil and gas industry and this document:

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Bcf. One billion cubic feet of gas.

BOE. One stock tank barrel equivalent of oil, calculated by converting gas volumes to equivalent oil barrels at a ratio of 6 thousand cubic feet of gas to 1 barrel of oil.

BOPD. Barrels of oil per day.

Btu. British thermal unit. One British thermal unit is the amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Developed oil and gas reserves. Developed oil and gas reserves are reserves of any category that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Development project. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

Development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Differential. An adjustment to the price of oil or gas from an established spot market price to reflect differences in the quality and/or location of oil or gas.

Economically producible. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities.

Estimated ultimate recovery (EUR). Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date,

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well or a stratigraphic test well.

Farmout. An assignment of an interest in a drilling location and related acreage conditional upon the drilling of a well on that location.

Gas. Natural gas.

MBbl. One thousand barrels of oil or other liquid hydrocarbons.

MBOE. One thousand BOE.

Mcf. One thousand cubic feet of gas.

Mcfd. One thousand cubic feet of gas per day

MMcfe. One million cubic feet of gas equivalent.

MMBOE. One million BOE.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of gas.

NYMEX. New York Mercantile Exchange.

Oil. Crude oil, condensate and natural gas liquids.

Operator. The individual or company responsible for the exploration and/or production of an oil or gas well or lease.

Play. A geographic area with hydrocarbon potential.

Proved oil and gas reserves. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project, within a reasonable time.

The area of the reservoir considered as proved includes all of the following: (i) the area identified by drilling and limited by fluid contacts, if any; and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil and gas on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establish a lower contact with reasonable certainty.

Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the twelve-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved reserve additions. The sum of additions to proved reserves from extensions, discoveries, improved recovery, acquisitions and revisions of previous estimates.

Reserves. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known

accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Reserve additions. Changes in proved reserves due to revisions of previous estimates, extensions, discoveries, improved recovery and other additions and purchases of reserves in-place.

Reserve life. A measure of the productive life of an oil and gas property or a group of properties, expressed in years.

Royalty interest. An interest in an oil and gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

Standardized measure. The present value, discounted at 10% per year, of estimated future net revenues from the production of proved reserves, computed by applying sales prices used in estimating proved oil and gas reserves to the year-end quantities of those reserves in effect as of the dates of such estimates and held constant throughout the productive life of the reserves and deducting the estimated future costs to be incurred in developing, producing and abandoning the proved reserves (computed based on year-end costs and assuming continuation of existing economic conditions). Future income taxes are calculated by applying the appropriate year-end statutory federal and state income tax rate with consideration of future tax rates already legislated, to pre-tax future net cash flows, net of the tax basis of the properties involved and utilization of available tax carryforwards related to proved oil and gas reserves.

SWD. Salt water disposal well

Undeveloped oil and gas reserves. Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Working interest. An interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations.

References herein to the “Company”, “we”, “us” and “our” mean Tengasco, Inc.

PART I

ITEM 1. BUSINESS.

History of the Company

The Company was initially organized in Utah in 1916 under a name later changed to Onasco Companies, Inc. In 1995, the Company changed its name from Onasco Companies, Inc. by merging into Tengasco, Inc., a Tennessee corporation, formed by the Company solely for this purpose.

OVERVIEW

The Company is in the business of exploration for 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 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”) owns and operates treatment and delivery facilities using the latest developments in available treatment technologies for the extraction of methane gas from nonconventional sources for delivery through the nation’s existing natural gas pipeline system, including the Company’s TPC pipeline system in Tennessee for eventual sale to natural gas customers.

The Company also has a management agreement with Hoactzin Partners, L.P. (“Hoactzin”) to manage Hoactzin’s oil and gas properties in the Gulf of Mexico offshore Texas and Louisiana. (See 4. Management Agreement with Hoactzin on page 12) As consideration for that agreement the Company obtained reimbursement from Hoactzin of a portion of salary and expenses for the Company’s Vice President Patrick McInturff, as well as an option to participate in production and exploration activities in Hoactzin’s properties in those areas. Peter E. Salas, the Chairman of the Board of Directors of the Company, is the controlling person of Hoactzin. He is also the sole shareholder and controlling person of Dolphin Management, Inc., the general partner of Dolphin Offshore Partners, L.P., which is the Company’s largest shareholder.

General

1. The Kansas Properties

The Kansas Properties presently include 184 producing oil wells in central Kansas. Our management and staff have a great deal of Kansas exploration and production experience. We have onsite production management and field personnel working in Kansas.

On July 2, 2008, the Company acquired 19 leases encompassing approximately 1,577 acres and 41 oil wells producing approximately 80 barrels of oil per day in Rooks County, Kansas together with salt water disposal wells and related equipment from Black Diamond Oil, Inc. for $5.35 million. The leases acquired are in the Company's core area in central Kansas and are a part of the larger Riffe Field. Polymer treatments on several existing wells resulted in an increase in production of the acquired wells to 147 BOPD by the end of 2008. Total production during the initial six month ownership period was 22 MBbls, an average of 122 BOPD. In 2009, despite very little freshly deployed capital, these wells averaged 111 BOPD.

In 2009, the decrease in oil prices, particularly in the first 6 months of the year, prevented the Company from having sufficient cash flow to remain as active in drilling new wells and performing polymer treatments as we had been in prior years. We had no capital spending until late 2009 and only drilled one salt water disposal well for the 2008 Albers discovery wells which produced 21 MBbls in 2009. We also performed 2 polymer jobs late in 2009 which added 2.9 MBbls to our production total.

In 2009, the Company continued to try to acquire key acreage and analyze seismic data to aid its exploration and development program. While the Company intends in 2010 to return to a more active drilling and workover program, the level of activity will be driven by cash flow. Those expectations can be tempered with a change in oil prices like we endured in late 2008 and early 2009. At the time of this writing, prices and our derivative position will allow a more active plan for 2010.

A. Kansas Ten Well Drilling Program

On September 17, 2007, the Company entered into a ten well drilling program with Hoactzin, consisting of three wildcat wells and seven developmental wells to be drilled on the Company's Kansas Properties (the "Program"). Under the terms of the Program, Hoactzin paid the Company $400,000 for each producing well and $250,000 for each per dry hole. The terms of the Program also provided that Hoactzin would receive all the working interest in the producing wells, and would pay an initial fee to the Company of 25% of its working interest revenues net of operating expenses, referred to as a management fee. The fee paid to the Company by Hoactzin will increase to 85% working interest when net revenues received by Hoactzin reach an agreed payout point of approximately 1.35 times Hoactzin's purchase price (the "Payout Point").

Nine of the ten wells in the program were completed as oil producers and are currently producing approximately 61 barrels per day in total. Hoactzin paid a total of $3.85 million (the "Purchase Price") for its interest in the Program resulting in the Payout Point being determined as $5.2 million. The Purchase Price paid by Hoactzin for its interest in the Program wells exceeded the Company's actual drilling cost of approximately $2.6 million for the ten wells by more than $1 million.

In 2009, the wells from the Program produced 22 MBbls of which 14 MBbls were net to Hoactzin. As of December 31, 2009, net revenues received by Hoactzin from the Program total $2.5 million which leaves a balance of $2.7 million until the Payout Point is reached.

Although production level of the Program wells will decline over time in accordance with expected decline curves, based on the drilling results of the Program wells to date and the current price of oil, the Program wells are expected to reach the Payout Point in approximately four years from first production. However, under the terms of the agreement reaching the Payout Point could be accelerated by applying 75% of the net proceeds Hoactzin receives from the methane extraction project developed by MMC at the Carter Valley, Tennessee landfill (the "Methane Project"), toward reaching the Payout Point. (The Methane Project is discussed in greater detail below.) The Methane Project net proceeds when applied would result in the Payout Point being achieved sooner than the estimated four year period based solely upon revenues from the Program wells.

On September 17, 2007, the Company entered into another agreement with Hoactzin providing that if the Program and the Methane Project in combination failed to return net revenues to Hoactzin equal to 25% of the Purchase Price by December 31, 2009, then Hoactzin had an option to exchange up to 20% of its net profits interest in the Methane Project for convertible preferred stock to be issued by the Company with a liquidation value equal to 20% of the Purchase Price less the net proceeds received at the time of any exchange. The conversion option would be set at issuance of the preferred stock at the then twenty business day trailing average closing price of Company stock on the NYSE Amex. This option could not have occurred at year-end 2009 because approximately 50% of the Purchase Price was returned to Hoactzin from revenues from the wells in the Program by the end of 2008. Hoactzin has a similar option each year after 2010 in which Hoactzin's then-unrecovered Purchase Price at the beginning of the year is not reduced 20% further by the end of that year, using the same conversion option calculation. The Company, however, may in any year make cash payment from any source in the amount required to prevent such an exchange option for preferred stock from arising. In addition, the conversion right is limited to a conversion of no more than 19% in the aggregate of the outstanding common shares of the Company. In the event Hoactzin's 75% net profits interest in the Methane Project were fully exchanged for preferred stock Hoactzin would retain no net profits interest in the Methane Project after the full exchange.

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

However, as stated, net revenues received by Hoactzin from the wells in the Program through December 31, 2009 totaled $2.5 million leaving a balance of $1.3 million to reach the point at which no preferred stock can be issued to Hoactzin thus making it highly unlikely that any preferred stock will ever be issued to Hoactzin. The Company notes that with the demonstrated successful results of production from the wells in the Program that the payout of 25% of the Purchase Price was reached by year-end 2008, a full year before the December 31, 2009 required date, therefore no requirement to issue preferred stock will arise in 2010. The Company further anticipates that at current prices of about $70.00 per barrel of oil and $6.00 per Mcf of gas, and at currently expected sales levels of methane gas from the Methane Project that the balance of the unrecovered Purchase Price by Hoactzin may be fully recovered by Hoactzin by year-end 2011. If this occurs the possibility of being required to issue any preferred ceases to exist. If it does not occur, the Company believes it is highly unlikely that any obligation to issue preferred stock will arise under the terms of this agreement at any time in the future, because the production results in any future year should readily satisfy the small production levels required to prevent an optional preferred stock issuance from arising in any year.

B. Kansas Production

The Company's gross oil production in Kansas decreased in 2009 from 2008 levels. In 2009, the Company produced 217 MBbls in Kansas compared to 232 MBbls in 2008. The two wells that were polymered in 2009 produced 2.9 MBbl and the one new well drilled in 2009 was a salt water disposal well (SWD) for the Albers lease.

Capital projects for the Company are funded by cash flow and in 2009 the Company had reduced cash flow, especially in the first 9 months of the year. We plan to be more active in 2010 as current oil prices have increased. However, decreases in future oil prices may cause the Company to reduce capital spending. In July 2009 the Company hedged a specified number of barrels of oil that currently constitutes about two-thirds of the Company's daily production to minimize this effect.

2. The Tennessee Properties

In the early 1980's Amoco Production Company owned numerous acres of oil and gas leases in the Eastern Overthrust in the Appalachian Basin, including the area now referred to as the Swan Creek Field. Amoco successfully drilled two natural gas discovery wells in the Swan Creek Field to the Knox Formation. In the mid-1980's, however, development of this field was cost prohibitive due to a substantial decline in worldwide oil and gas prices which was further exacerbated by the high cost of constructing a necessary 23-mile pipeline to deliver gas from the Swan Creek Field to the closest market. In July 1995, the Company acquired the Swan Creek leases and began development of the field.

A. Swan Creek Pipeline Facilities

The Company's completed pipeline system is owned and operated by Tengasco Pipeline Corporation ("TPC"), the Company's wholly-owned subsidiary and extends 65 miles from the Swan Creek Field to a meter station at Eastman Chemical Company's ("Eastman") plant in Kingsport, Tennessee. The pipeline system was built for a total cost of $16.4 million.

B. Swan Creek Production and Development

The Company has concluded based on the results of previously drilled wells and seismic data that drilling new gas wells in the Swan Creek Field would not achieve any significant increase in daily gas production totals from the Field. Current wells in production in the Swan Creek Field would be capable of and would likely produce all the remaining reserves in that Field. As a result, the Company has not drilled any new gas wells in the Swan Creek Field since 2004.

Because no drilling for natural gas in the Knox formation in Swan Creek is anticipated in the future, the current production levels less decline are the sole value of natural gas reserves and production. The existing production and the current 16 wells producing natural gas are showing typical Appalachian production declines, which exhibit a long-lived nature but more modest volumes. The experienced decline in actual production levels from existing wells in the Swan Creek Field from 2008 to 2009 was expected and predictable. Although there can be no assurance, the Company expects these natural rates of decline in the future will be comparable to the decline experienced over the 2008-2009 period.

During 2009, the Company had 17 producing gas wells and 4 producing oil wells in the Swan Creek Field. Gas sales from the Swan Creek Field during 2009 averaged 124 Mcfd compared to 215 Mcfd in 2008.

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

By the end of 2008, Jacobs Energy had re-completed the Ted Hall No. 1 well, which constituted the completion of the first of the two test wells under the farmout agreement. On July 8, 2009, the Company terminated the farmout agreement with Jacobs Energy under its terms. The Company determined that the first of the two test wells contemplated by the agreement was not properly completed and evaluated for nitrogen content. It was never determined how much of the nitrogen was occurring naturally, and how much was a result of the completion management. Second, the Company determined that Jacobs Energy had failed to perform in a commercially timely manner by not having yet drilled the second test well. Jacobs Energy had stated to the Company in early July 2009 that for the foreseeable future it would not be economically feasible for Jacobs Energy to drill the second test well based on Jacobs's assessment of the current state of the financial markets. Based on that statement, together with the removal of Jacobs' equipment from the first well, the Company determined that Jacobs had abandoned its obligations under the agreement, constituting a separate basis for the Company's termination of the agreement. Because the agreement was terminated, no assignments of any interest in any properties were made, and no such assignments are due to be conveyed to Jacobs Energy,

The Company continues to seek development of these properties with other industry partners as it remains possible that when more than one well is drilled, it may be economically feasible to treat (if necessary) the produced gas as required, and to construct gathering facilities necessary to connect to the Company's pipeline to bring the gas to market. To date no industry partners have been found by the Company to further explore these properties and no assurances can be made that such a partner can be found or that an agreement may be reached with such partner on terms acceptable to the Company.

3. Methane Project

On October 24, 2006, the Company signed a twenty-year Landfill Gas Sale and Purchase Agreement (the "Agreement") with BFI Waste Systems of Tennessee, LLC ("BFI"), an affiliate of Allied Waste Industries ("Allied"). In 2008, Allied merged into Republic Services, Inc. ("Republic"). The Company assigned its interest in the Agreement to MMC and provides that MMC will purchase the entire naturally produced gas stream being collected at the Carter Valley municipal solid waste landfill owned and operated by Republic in Church Hill, Tennessee serving the metropolitan area of Kingsport, Tennessee. Republic's facility is located about two miles from the Company's pipeline. The Company installed a proprietary combination of advanced gas treatment technology to extract the methane component of the purchased gas stream. Methane is the principal component of natural gas and makes up about half of the purchased raw gas stream by volume. The Company has constructed a pipeline to deliver the extracted methane gas to the Company's existing pipeline (the "Methane Project").

The total cost for the Methane Project, including pipeline construction, was approximately $4.5 million. The costs of the Methane Project were funded primarily by (a) the money received by the Company from Hoactzin to purchase its interest in the Ten Well Program which exceeded the Company's actual costs of drilling the wells in that Program by more than $1 million; (b) cash flow from the Company's operations; and (c) $0.8 million of the funds the Company borrowed under its credit facility with Sovereign Bank of Dallas, Texas ("Sovereign Bank"). Methane gas produced by the project facilities was initially mixed in the Company's pipeline and delivered and sold to Eastman under the terms of the Company's natural gas purchase and sale agreement with Eastman. At current gas production rates in the landfill itself and expected extraction efficiencies, the Company estimates it will be able to produce and deliver about 400 Mcfd of methane sales gas. The gas supply from this landfill is projected to grow over the years as the underlying operating landfill continues to expand and generate additional naturally produced gas, and for several years following the closing of the landfill, estimated by Republic to occur between the years 2022 and 2029. Gas production will continue in commercial quantities up to 15 years after closure of the landfill.

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

Initial test volumes of methane were produced in late December 2008. During the first two months of 2009, Eastman was reviewing its current air quality permits with regard to MMC's methane production and deliveries did not occur during that review.