Chamber Lift – A Technology For Producing Stripper Oil Wells – Stage II
during the Period 7/1/2003 to 12/31/2004

By

D.K. Johnson and R.W. Watson

The Pennsylvania State University
The College of Earth and Mineral Sciences
The Department of Energy and Geo-Environmental Engineering
The Energy Institute

B. Miller
Bretagne, G.P., Lexington KY

Report Issued: December 31, 2004

Work Performed Under Prime Award No. DE-FC26-00 NT 41025
Subcontract No. 2556-TPSU – DOE - 1025

For
U.S. Department of Energy
National Energy Technology Laboratory
P.O. Box 10940
Pittsburgh, Pennsylvania 15236

By
The Pennsylvania State University
The College of Earth and Mineral Sciences
The Department of Energy and Geo-Environmental Engineering
The Energy Institute

Bretagne, G.P., Lexington KY

ABSTRACT

The largest expense associated with operation of most stripper oil wells and many stripper gas wells are the lifting costs associated with the removal of fluids from the well bore. The predominate artificial lift method used is rod pumping. Much of the existing equipment is oversized, outdated and the maintenance costs required to keep this equipment operational are large and continue to increase. One option for replacing rod pumping, is to use an intermittent gas chamber lift system. The gas chamber lift system reported here is specifically being developed as a fluid lift system for low volume wells. The system uses newer types of materials for tubulars to minimize capital costs and reduce maintenance associated with corrosion and mechanical wear. Other advantages of the system include: easy conversion from a rod-pumping system; minimal mechanical and electrical equipment at the well-site; fewer down-hole moving parts; and less labor intensive procedures for repair

Bretagne GP, an independent producer, teamed up with Penn State University and made a proposal to design and field test a chamber gas lift system. An initial study was performed with a lab scale model at Penn State and a field test of a well equipped with a prototype of the "chamber-lift system." The current study focuses on field testing of the concept. Two wells have been equipped with the chamber lift system. Different completion methods have been utilized, such that testing of the system using different operating conditions can be performed. The chamber-lift system has been successfully operated using a conventional surface controller. Moreover, the surface controller was actuated using electrical power generated at the well-site using a solar panel.

TABLE OF CONTENTS

LIST OF FIGURES……………………………………………………………………….v

1.0 INTRODUCTION…………………………………………………………………….1

2.0 FIELD WORK……………………………………………………………………..4

3.0 RESULTS…………………………………………………………………………10

4.0 CONCLUSIONS……………………………………………………….………14

REFERENCES…………………………………………………………………..…16

LIST OF FIGURES

Figure	Title	Page
1	Typical Beam Pump……………………………………………………..…1	
2	Chamber Lift System at Penn State……………………………….……….3	
3	Well # 33……………………………………………………………..…5	
4	Schematic of Well #33…………………………………………….………6	
5	Trip Tank to Measure Volume of Fluid Produced from a Lift……….....8	
6	Echo Meter Used for Determining Fluid Level Down-hole…………….....8	
7	Bubble Tube Installation……………………………………………..9	
8	Photo of Well #33 Taken Jan 8, 2004…………………………………11	
9	Pressure Data from Well #33 on January 7,2002……………………....12	
10	Service Rig Pulling Pipe from Well #33 July……….........................13	
11	Pressure Data from Well #33 on July 21, 2004………………………..14	

1.0 Introduction

Project Background

The typical stripper oil well in the United States produces only a few barrels of crude oil per day. Most domestic stripper wells are operated by independents rather than by large integrated oil companies. The fundamental challenge at hand is determining the most economical method to operate these wells in order to lift the crude oil from the well-bore, to the tank batteries. It is this lifting cost that is the single largest expense attendant to the operation of these stripper wells. There are currently many different technical approaches to lifting liquids from the well-bore. These include: Beam pumps, plunger lift, gas lift, electric-submersible pumps. The most common method currently used is the beam pump that is shown in Figure 1. However, beam pumps have several drawbacks. It could be argued that the largest drawback is the maintenance cost attendant to keeping

Figure 1. Typical Beam Pump

beam pumps continuously operating. Clearly an option to the use of beam-pumps is desirable. To this end, Bretagne G.P. and the Pennsylvania State University collaborated in an investigation that was funded by the Stripper Well Consortium (SWC) during 2001. The approach utilized was to improve and modify existing gas lift technology for use in stripper wells by independent-operators. The primary goal of the original study was to optimize the gas lift system by building a laboratory scale model at Penn State. Experience gained through testing with the lab scale model was then implemented into a full scale field test on an existing well operated by Bretagne G.P. in the Big Sinking Field located in eastern Kentucky.

Lab Scale Model

During the previous phase of the current project, a working laboratory scale model of an intermittent gas lift system was designed and constructed at Penn State. This work was carried out by a graduate student whom used this research as the basis for his PNG Masters Thesis[1]. The basic geometry of this system was two concentric strings of steel pipe. The outer string was constructed of 2 inch steel pipe with an inter string of 1 inch steel pipe. This system was operated by injecting the lift gas down the annulus space created between the 2 inch and the 1 inch pipe. Fluid was then produced up the 1 inch pipe. An adjustable back pressure regulator was placed at the outlet of the fluid siphon string to replicate the friction and fluid head encountered in the full scale system in the field. Figure 2. shows this experimental setup at Penn State. The overall height of the system is approximately 20 feet.

The reservoir was replicated by a large pressurized tank filled with fluid. (gray tank in Figure 2) This tank was pressurized with compressed air and the pressure was a variable in the test matrix that replicated the reservoir pressure in the actual field. A standing valve was placed at the bottom of the outside string allowing fluid to enter the chamber and rise to a level where the fluid head was equalized with the reservoir pressure. (Pressure in the gray tank) When a lift was initiated by sending compressed air down the annulus between the strings of pipe, the standing valve would close and prevent fluid from returning into the reservoir. The fluid would then be forced up the 1 inch dip tube and to the "surface". The lift system was instrumented with pressure transducers, (static and differential), a thermocouple, and liquid and gas flow meters. This data were then recorded using a laptop equipped with LabView data acquisition software. A test matrix was setup by varying the composition of a mixture of mineral oil and water as the fluid being lifted. The gas injection pressure and the reservoir pressure were the other two variables in the test matrix. Later testing was performed with crude oil from the same field as the full scale test.

Figure 2. Chamber Lift System at Penn State

The laboratory research was done in conjunction with an initial field test in the Big Sinking Field, Kentucky. The field test was conducted by converting a producing well using a beam pump, to an intermittent gas lift system. The initial geometry was similar to the lab scale setup described above with one fundamental difference. For the first field test, the lift gas was injected down the 1 inch pipe, and fluid was to be produced up the annulus space. However, the gas compressor being used could not generate enough pressure to lift the fluid up the annulus space. So in order to successfully lift the fluid slug to the surface, the gas was injected down the annulus and the fluid produced up the 1 inch pipe. The lab scale apparatus was set up to mimic this geometry.

Objective

The objective of this study was to further develop and optimize the intermittent gas lift technology for use on low production stripper wells. Specifically, several areas were to be considered. First was a performance comparison between wells with and without a “rat hole” below the formation perforations to reduce the hydrostatic head on the formation and thereby increase fluid production. Second was to determine the optimum gas lift timing cycle to minimize the volume of lift gas consumed per barrel of fluid produced. Third was to investigate the best injection/production tubular combination. There are many different configurations that can be used along with many different tube diameter ratios that can be considered. A cross sectional area ratio between the lift string and production string was investigated in order to provide operators a “rule of thumb” for designing gas lift systems for use in other oil and gas fields. An additional goal was to measure the minimum volume of lift gas required to produce a barrel of liquid, and thereby increase the overall efficiency of the system.

2.0 Field Work

For the current SWC project, (Stage II) several changes were proposed to improve the gas lift system. The first was to replace the gas compressor with a different unit that could deliver higher pressures to the well-head. Second, two new wells were drilled specifically for this project during October 2003. These wells were drilled through the producing formation to a depth that provided approximately 300 feet of “rat hole”. This permitted the positioning of the chamber of the lift system to various depths below the perferations. This permitted analyses of the system’s performance using different configurations. The advantage of placing the chamber below the formation is that by adjusting the time between lifts, the fluid level in the casing can be kept at or below the perforations. If the fluid level is held below the perforations, it eliminates the hydrostatic head that the fluid column would typically put on the formation at the well bore. This allows fluid to flow into the well bore more rapidly.

The gas injection geometry was also changed to direct the gas down the annulus and produce fluid up the 1-inch string. Figure 3 shows the control valves and piping at the surface for this arrangement.

Figure 3. Well # 33

Membrane generated nitrogen was used as the lift gas for all field tests conducted because it was available on site for an ongoing huff and puff stimulation project. The gas injection line is pointed out in Figure 3. The injection of the lift gas is controlled by the large red valve that is plumbed into the gas injection line. The second red control valve shown, was not used for any of the field tests discussed in this report. Tests of the system indicated that it was not required for the operation of the system.

Figure 4 shows a schematic of well #33, one of the two new wells drilled for this project. This well was completed on October 13, 2003. The well was drilled to a total depth of 1653-feet. The wellbore diameter is 6-1/4-inches. 4-1/2-inch OD (outside diameter) casing was run to a depth of 1,627 feet. The casing was completed by perforating the casing from 1,342 and 1,362 feet. The producing formation is the Keefer sandstone located between 1,334 feet and 1,391 feet.

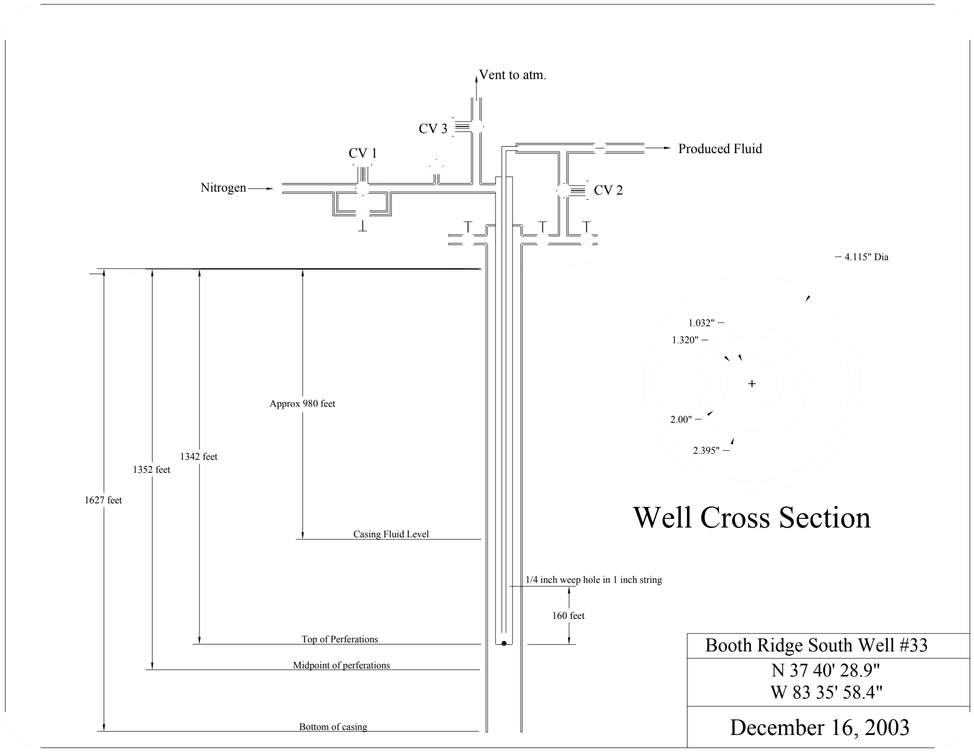

Figure 4. Schematic of Well #33

The gas injection/fluid production configuration in Figure 4 is the same as shown in Figure 3. The injection of nitrogen gas is controlled by control valve 1 (CV1 Figure 4). Nitrogen then passes down the 2-inch by 1-inch annulus to the bottom of the chamber where a standing valve is positioned at the height of the top of the perforations. The position of the standing valve was lowered deeper in the well for later testing. The slug of produced fluid is then forced up the one inch tubing string. Once the fluid reaches the surface it is directed to the separator and stock tanks via 2 inch poly tubing. The typical interval between lifts ranged from 10 to 15 minutes. A Weatherford controller powered by a small solar panel, was used to operate the nitrogen inlet control valve. The nitrogen bleed-off valve is not shown in Figure 3. Operation of this valve will be discussed more in the results section.

Special data acquisition devices were implemented to monitor and record the performance of the two new test wells. Two Omega Engineering pressure transducers from were placed in the system. One measured the pressure on the nitrogen gas supply line that is located at the surface and the second measured the pressure on the fluid production line that is also located at the surface. Data from these two transducers were recorded every 10 seconds on a laptop computer using LabView software. The volume of nitrogen used for each lift was determined using a 1-1/4 inch orifice plate. The line pressure and differential pressure were recorded on a 24 hour circular chart recorder. By integrating the circular charts, the total volume of gas used for each lift was found.

Determination of the liquid volume attained during each lift-cycle proved to be the most challenging measurement. In order to obtain this data, a trip tank was designed and fabricated. Figure 5 is a photograph of the completed trip tank plumbed into the fluid production line on one of the test wells. As viewed in Figure 5, produced fluid (oil and brine) is transported through the 2 inch plastic pipe from the lower right hand side of the photo, and up into the top of the white tank. This 55 galloon tank is semi-transparent and has graduation marks along the side that allows the operator to read off the volume of fluid from a specific lift. After a measurement has been taken, the fluid is then allowed to drain into the 30 gallon steel tank below. Nitrogen readily available from the lift gas line is then used to pressurize the bottom tank to approximately 50 psi. This pressurized nitrogen is then used to drive the fluid from the lower tank to the stock tanks. The process can then be repeated for the next lift.

Other data required for the analysis of the behavior of the chamber-lift are knowledge of the fluid height/depths in the annulus between the casing and tubing and the chamber itself. The chamber in this particular case is the inside of the 2 inch steel pipe. These measurements were made by using two different techniques. First was by using a commercially available echo meter. The echo meter works on the principle of creating a sound wave that travels from the surface, down the casing, reflects off the surface of the fluid and bounces back to the top of the well where the sound wave is picked up by a sensitive pressure transducer. Using the speed of sound of the gas in the casing, a laptop computer computes the distance down-hole to the surface of the fluid. The echo meter used for this project is shown in Figure 6, on the left side of the pipe wrench. On the far left side of the echo meter, is a small chamber that is pressurized with carbon dioxide. A firing pin device rapidly opens and sends a transient pressure wave down the casing.

Figure 5. Trip Tank to Measure Volume of Fluid Produce from a Lift

Figure 6. Echo Meter Used for Determining Fluid Level Down-hole

The second method of determining fluid levels down-hole is by using a bubble tube. A small amount of gas is injected into small-diameter tubing that is run from the surface to below the fluid level. The pressure required at the surface to move one bubble of gas from the foot of the tubing into the liquid-column is equal to the fluid head above the bottom of the bubble tube. Figure 7 shows the installation of two bubble tubes in one of the chamber lift test wells. The tube itself is ¼ inch OD, 1/8 inch ID Polyethylene tubing supplied by Cobon plastics. One bubble tube is place on the outside of the two inch steel pipe and a second is connected to a 90 degree elbow that is welded to the 2 inch pipe that permits measurement of the fluid height in the chamber. The photograph shown on Figure 7 was obtained immediately prior to lowering the 2 inch pipe into the well. Data collected using the bubble tubes will be discussed in the results section.

Figure 7. Bubble Tube Installation

3.0 Results

Two test wells (referred to as Wells# 33 and #39) were drilled specifically for this project. These wells located in the Big Andy Field in Eastern Kentucky were drilled during October 2003. Testing of these two wells began in December 2003. The original wellhead configuration permitted injection of nitrogen gas into the 2 x 1 annulus with fluid production up the 1 inch tubing string. Gas injection was controlled by an automated valve at the surface. Injection time and time between lifts were the two parameters that were varied during this set of tests.

A quarter inch weep hole was drilled in the one inch tubing string 160 feet above the standing valve. The purpose of the weep hole was to permit the pressure to equalize between the one inch string and the 2 x 1 annulus and thereby maximize the amount of liquid that would accumulate in the chamber before the next lift. The well-tender observed the presence of emulsions that coincided with initialization of production. It was hypothesized that the presence of the weep hole contributed to the formation of emulsions by increasing the amount of liquid agitation. The solution to the emulsion problem was to add a control valve at the surface that depressurized the 2 x 1 inch annulus after the fluid slug had been sent to the stock tanks. Figure 8 shows a photograph of well 33 taken January 8, 2004 shortly after the depressurization valve and vent were installed. The vent line can be seen extending above the truck in the photograph. The red control valve can also be seen mounted in the vent line.

Two pressure transducers were used to monitor the gas injection pressure and the fluid production pressure. This pressure data were monitored and recorded using a laptop computer located inside the tent shown in Figure 8. Data from one lift have been plotted in Figure 9. The nitrogen lift gas pressure and the production fluid pressure are both shown on this same plot. Gas was injected for one minute. An orifice plate and differential pressure gauge in the gas supply line were used to calculate the total volume of gas used for each lift. For this particular lift, 380 standard cubic feet of nitrogen was used to lift the fluid from the well-bore. For this lift it took approximately two and a half minutes from the time the gas injection started until the first fluid reached the surface. The production fluid pressure spiked at about 20 psi and quickly dropped to about 5 psi for the remainder of the lift. The observed production fluid pressure is largely a function of the friction and the change in the elevation of the production fluid line from the well head to the stock tanks. Well #39 was several hundred yards further away from the stock tanks than was well #33. Therefore when the fluid slug reached the surface, the observed fluid production pressure was higher.

Figure 8. Photo of Well #33 Taken Jan 8, 2004

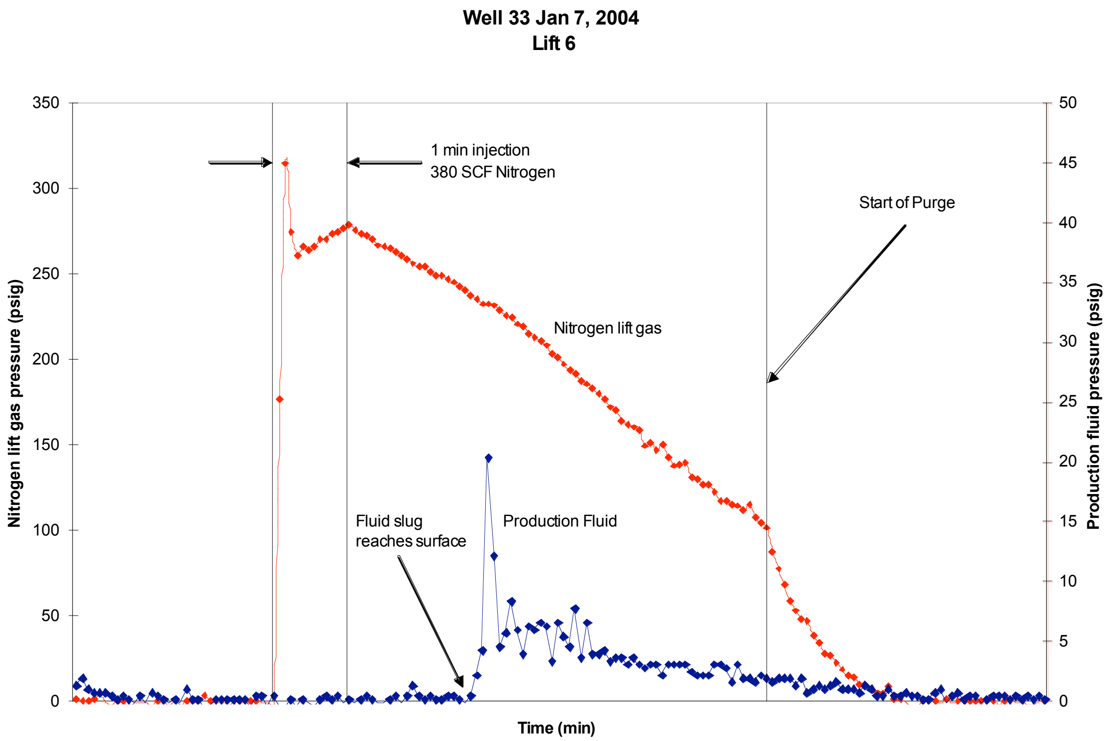

Figure 9. Pressure Data from Well #33 on Jan 7, 2004

The start of the nitrogen lift gas purge was six and a half minutes from the time the gas injection was started. The fluid slug had already reached the stock tanks by this time. Depressurizing the lift gas line was effective in permitting the chamber at the bottom to refill to its maximum capacity. However, the vented gas was a detriment as far as the overall energy efficiency of the system. The 2 by 1 inch annulus has a larger volume than the 1 inch string. Depressurizing the annulus following each cycle resulted in the venting of more gas than if the system was operated in the opposite direction. The trade off to producing in the opposite direction (fluid produced up annulus) is that there is more frictional pressure loss. The increased frictional pressure loss results from the larger surface area of the annulus space.

The next step in the field testing was to obtain an accurate measurement of the fluid produced for each lift. This measurement was obtained using the trip tank that was described in Section 2.0 of this report. During July 2004 the pipe was pulled from the well in order to permit the running of the bubble tube. The details of the bubble tube are also described in detail in Section 2.0 of this report. Figure 10 shows a picture of the service rig pulling pipe from Well #33 July 2004. When the pipe was run back into the well, ten additional joints of pipe were added in order to lower the chamber approximately 300 feet into the rat-hole. The purpose for this was to gain additional fluid volume per lift. The two inch pipe was run down-hole until it hit bottom and was then pulled off bottom about 10 feet and set into the slips.

Figure 10. Service Rig Pulling Pipe from Well #33 July 2004

Figure 11 shows the data collected from one lift on well #33 after the chamber had been lowered to a distance of about 300 feet below the perforations. Because the chamber could now accumulate more fluid than it could when it was set at the height of the perforations, each lift resulted in a larger liquid volume. Using the trip tank, the volume of this particular lift shown in Figure 11 was measured to be 18.5 gallons. The duration of the nitrogen injection was 1 minute 10 seconds and had a volume of 320 standard cubic feet of nitrogen.

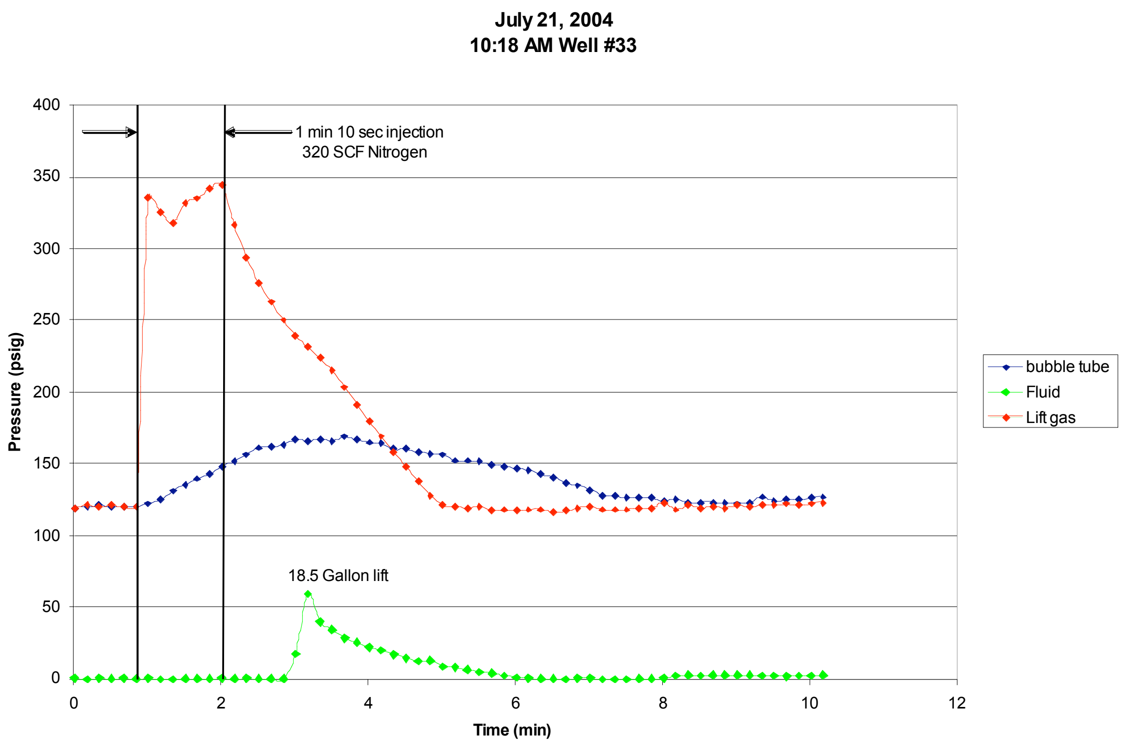

Figure 11. Pressure Data from Well #33 on July 21, 2004

4.0 Conclusions

Independent oil producer Bretagne G.P. is currently operating about 500 wells with conventional beam pumps. Nitrogen is utilized to stimulate oil-production from the Big Andy Field, Kentucky. Bretagne is evaluating the best method to expand the project by placing an additional 100 currently shut in wells, onto production. Two types of fluid lift systems are being evaluated for the additional wells: 1) down-hole electric diaphragm pump (HDESP) 2) intermittent gas chamber lift. Three of the HDESP pumps have been run and are being evaluated.

The intermittent gas chamber lift system is being redesigned with several new improvements over the systems tested to date and reported here. The current plan is to use a parallel string geometry instead of a concentric tube geometry. The parallel string geometry will offer excellent flexibility to optimize the chamber lift system design parameters such as: 1) gas supply pressure, 2) fluid volume per lift, 3) depth of lift. Also the surface control system will be re-designed to use smaller more efficient tubulars and will be easier to install with a modular control system. Current field tests with the concentric tube geometry have shown two important results. If fluid is produced up the 1 inch tubing string, there is too much tail gas produced. If the fluid is produced up the 2 by 1 inch annulus, then there is too much friction loss. This conclusion has led to the decision to pursue the parallel tubing geometry in future work.

Several other design guidelines have come out of the current field testing experience. The primary efficiency metric has been identified as the volume of lift gas used per barrel of fluid produced. A realistic target has been set for 750 cubic feet of lift gas per barrel of fluid. In order to meet this target it has been determined that a 7:1 chamber to lift string cross sectional area should be used. And also, the gas supply string should be about half the cross sectional area of the lift string.

To summarize these design guidelines, the following scenario is an example of the system being looked at for future production in the Big Andy Field. The gas lift system design parameters are: 1) gas supply pressure of 300 psi, 2) fluid volume to be lifted of 6 Barrels per day, 3) depth of lift of 1400 feet. The casing size in this example is given to be 4 ½ inch, (4.05" I.D.). Ultimately the use of 2 coiled poly tubing strings will be superior to a system of one tubular joint string to take the axial loading and a coiled second parallel string, but at this time the latter is show to be more efficient. The chamber would be located at or below the perforations and would be taking fluid off the bottom. The chamber will be designed to accumulate the size of cycle volume that will yield approximately a 300 foot column in the lift string. By limiting the size of the chamber, the difficulties with initial unloading will be minimized.

REFERENCES

1) Petrof III, E.M., "An Experimental Study of Chamberlift System Optimization", M.S. Thesis in Petroleum and Natural Gas Engineering, The Pennsylvania State University, December 2003.