DOWNHOLE GAS SEPARATORS – A LABORATORY AND FIELD STUDY

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ABSTRACT

Downhole gas separators are often the most inefficient part of a sucker rod pump system. This paper presents laboratory data on the performance of five different gas separator designs. Only continuous flow was studied. Field data is presented on one of the designs. The field data indicates that success or failure of the gas separator is dependent upon the fluids and wellbore pressures as well as the mechanical design of the gas separator. Successful and unsuccessful examples of gas separator performance in the field are shown along with field fluid data properties. Videos will be shown at the presentation of the continuous and intermittent flow of water and air through the transparent gas separators placed in transparent casing. While the study is not completed, this is the first of hopefully several papers that will present the results of this investigation.

INTRODUCTION

Patterson[1] studied some different down-hole gas separation designs for coal bed methane operations in Wyoming. In these designs the inlet to the gas separators were smaller than normally used and along with some baffles, thought to allow gas to vent from inside the gas separator, obtained good gas separation in the field installation. While field installations provide the ultimate validation of gas separator performance, it is extremely difficult to isolate the influence of each design parameter. It was these installations which prompted the laboratory study of the gas separator geometry to understand if the "rules-of-thumb" used by the industry for gas separator design were valid.

One of the most common sources of inefficiency in oil well pumping installations (rod pumps, ESPs of PC pumps alike) is gas interference, which prevents the pump from delivering liquid at the design rate. Although this is a well known effect, there seems to be limited understanding of the mechanisms that control gas interference and this often results in the use of remedies, such as installing downhole gas separators, that are ineffective or even detrimental to the pumping system performance.

The objectives of this paper are to give a clearer insight on the mechanisms of gas interference in pumping wells and to present the results of recent laboratory and field studies on the flow characteristics and performance of some downhole gas separators.

In a pumping installation, one of the **principal functions of the wellbore is to operate as a two-phase (gas-liquid) separator** so that the pump (which is designed to pump liquid) can operate efficiently. Although this concept appears to be obvious, it seems to be totally ignored by most operators when they design completions and install hardware (gas anchors and the like) to combat the effects of gas interference.

In these applications, the separation of gas from liquid is achieved through GRAVITY separation without the introduction of other mechanisms (centrifugal forces, nozzles, etc.). Thus, the difference in density between the gas and liquid is the main driving force to be used for separation. This also implies that forces that oppose the effect of gravity, such as viscous drag caused by high fluid velocity and turbulence, will be detrimental to the separation process. Thus, high velocity of liquid or gas should be avoided if possible.

The Pumping Wellbore as an Efficient Gas-Liquid Separator

The preferred pumping installation for maximum pump efficiency requires installing the pump intake BELOW the lowest point of fluid entry into the wellbore and requires having an open casing-tubing annulus from the bottom to the wellhead. This configuration is shown in Figure 1A.

Gas and liquid enter the wellbore through the perforations and liquid flows to the bottom of the well under the action of gravity. The lighter gas bubbles rise through the liquid forming a gaseous liquid column, from the bottom of the perforated interval to the fluid level, then gas flows through the casing-tubing annulus to the wellhead where it exits to the flow line. Practically 100% liquid accumulates at the bottom of the well and enters the pump intake to be discharged by the pump into the tubing.

This completion is similar to the surface facility vertical two-phase separator shown in Figure 1B. To be equivalent both the x-sectional area for flow diameter to length ratios would have to be the same. The gas-liquid mixture enters the vessel about two-thirds up the vessel wall. The gas outlet is at the top of the vessel; Liquid falls to the bottom and accumulates in the "quieting chamber" of the vessel where it flows to the pump intake through the liquid outlet. Proper operation of the separator requires that the liquid retention time be sufficient for most of the gas bubbles to rise to the gas/liquid interface and that the gas velocity be low enough for most of the liquid droplets to fall to the gas-liquid interface. These are the two criteria used for correctly sizing the separator to meet the flowing requirements.
The unusual characteristics of this "equivalent separator" are that:

- It would have to be built with 4 to 7 inch diameter pipe
- It would be at least 30 feet tall
- It would not have liquid level controls

The capacity of a 2-phase separator is defined in terms of liquid and gas capacity as a function of operating pressure and gas and liquid densities

Gas Capacity

It is based on not exceeding the velocity of gas that will carry liquid droplets to the gas outlet. Typically, surface facility separators are designed to allow settling of liquid drops larger than 100 microns (0.005 inches) with the smaller drops being removed later by a mist extractor.
In **the wellbore** case, if gas carries liquid to the top of the annulus does not really constitute a gas capacity limitation since the liquid will eventually be produced at the wellhead. However, it will cause problems with the pumping system if sufficient liquid does not fall to the lower part of the well to insure that the pump intake is fed liquid at the rate that the pump is pumping. For this reason the **gas velocity in the annulus** must be considered in the design of the installation. In the best scenario, there is no surging of the liquid flow due to the gas flow allowing the pump displacement to consistently match the liquid production.

Liquid Capacity

The liquid capacity of normal diameter (3 – 5 feet) surface facility separator is determined based on the liquid retention time necessary for gas bubbles to migrate to the gas-liquid interface. For common oil and gas mixtures, values of the order of 1 to 2 minutes (determined from tests with fluid samples) are used in sizing separators and calculating the volume of the quieting chamber. This concept assumes that the liquid is virtually **stationary** and the gas bubbles are responding only to gravity and buoyancy forces. If the design liquid capacity is exceeded, then the liquid effluent will carry some gas to the next stage of separation (separator or storage tank) perhaps causing a process upset. The production limitation of a surface separator rarely equals the theoretical separator liquid capacity because the production is not constant.

The concept of retention time is not applicable to the wellbore since, due to the small flow area, the downward liquid velocity is of the same order of magnitude as the rising velocity (slip velocity) of the bubbles. If the liquid velocity exceeds the slip velocity of the gas, the bubbles will eventually be carried to the pump intake regardless of the distance (volume) between the casing perforations and the entrance to the pump. Therefore, the liquid capacity of the wellbore separator is determined by the maximum downward liquid velocity that does not entrain gas bubbles that are characterized by a certain design slip velocity.

Liquid Level Control

The liquid level in a separator is dependent on the relationship between the flow rate leaving the separator and the liquid rate entering the vessel. The liquid level will stabilize at some height only when the flow rate into the separator equals the flow rate out. This is very difficult to achieve under normal surface facilities flowing conditions and for this reason a dump valve which is actuated by a liquid level sensor is installed in most separators to maintain a gas/liquid interface within an appropriate operating range.

In the wellbore, it is not customary to control the liquid level by continuous direct monitoring of the fluid level. If the liquid flow through the perforations into the wellbore exceeds the pump delivery, the liquid will accumulate in the wellbore, the fluid level will rise, the flowing bottom-hole pressure will increase and the flow into the well will be reduced due to the additional back pressure. Although this will result in a stable fluid level it also may result in a situation where the well is not producing at the optimum rate. If on the other hand the liquid inflow is less than the pump delivery, the liquid level will fall to the pump intake and gas will flow into the pump resulting in a "pumped-off" condition. In the wellbore, the closest thing to a dump valve liquid level control is the installation of a Pump-Off controller, which senses a change in operating conditions at the surface and shuts down the pump for a sufficient period to allow the liquid to accumulate in the annulus before restarting the pump. If fluid inflow into the well is stable over long periods, the pump-off controller can be substituted with an ON-OFF timer.

The Pumping Wellbore as an Inefficient Gas-Liquid Separator

In a number of wells, it is not possible to install the pump intake below the lowermost fluid entry point in the wellbore. Typically, this is caused by the absence of sufficient rat-hole, the presence of liners or gravel packs or the fear of sanding up and sticking the pump. In this case, the efficiency of the wellbore as a gas-liquid separator will be severely reduced since there will always be some gas present at the pump intake.

The "Backwards" Separator

Installing the pump with the intake above the perforations, as shown in Figure 2A is equivalent to connecting a surface facility two-phase separator backwards so that the fluid inlet is at the bottom of the vessel and the liquid outlet is half way up the wall, as shown in Figure 2B. This is something that no operator with a minimum of common sense would do, especially if he were to deal with a 5-inch diameter separator!
As gas moves past the pump intake, a large number of the bubbles, which are always present, will be drawn into the pump reducing the efficiency and the pump's liquid throughput.

Tubing with a Downhole gas Separator as a Two Stage Separation System

If it is not possible to lower the pump intake, then a method to improve the pump's liquid fillage is to install an efficient down-hole gas separator. This is equivalent to implementing a second stage of separation in a surface facility to further process the fluid and separate additional gas from the liquid.

In this downhole system, shown in Figure 3, the **first stage** of gas/liquid separation occurs in the well bore's tubing/casing annulus. A large percentage of the gas flows past the bottom of the tubing, then bubbles through the annular gaseous liquid to the depth of the liquid level, then to the surface and out through the casing valve. At the separator intake, a mixture of gas and liquid enters the **second stage** downhole gas separator where further separation of gas and liquid takes place. The amount of gas that then flows with the liquid into the dip tube and to the pump intake is thus reduced to a minimum.

To maximize the volume of liquid that flows into the pump there are two options:

1. Increase the fraction of liquid that flows into the separator through its entry ports.
2. Facilitate further separation of gas and liquid within the separator so that an increased liquid fraction exits the separator.

The best results should be obtained when both processes are optimized.

This suggests that to design an efficient downhole separator we need to understand the effects of flow conditions in the casing annulus and separator entry-port geometry on the fluid flow into the separator as well as the gas-liquid separation mechanism taking place within the separator. In the past, the separator design emphasis has been on the internal separation process. This resulted in guidelines limiting the velocity of the liquid flowing between the dip tube and separator inner wall, to a generally accepted value of less than 6 inches per second.
In the study reported here, the primary objective was to study the effect of entry port geometry and location on the overall performance of the downhole separator, while also observing the flow mechanism within the separator.

Separator Output Liquid Fraction

It has been customary to express the performance of a downhole separator in terms of a "Separator Efficiency" that is defined as the ratio of the gas rate rejected by the separator to the total free gas rate flowing in the annulus at the depth of the separator:

Separator Efficiency= Es = Qgs/Qgt

Where Qgs = in-situ gas flow rate in annulus above separator cu.ft. /day
Qgt = in situ gas flow rate in annulus below separator, cu.ft. /day

Ideally, this quantity should be equal to 1.0 for a perfect separator allowing no gas to flow through to the pump. Although this quantity may be used for comparing the performance of various separators, it is not as useful in determining the effect of the separator on the liquid fillage of the pump.

It is more convenient to define a separator output liquid fraction as the fraction of total flow rate exiting the separator that is liquid, expressed at standard conditions:

Separator Output Liquid Fraction=OLFs = Qlout/(Qlout + Qgout)

Where: Qlout = liquid flow rate at separator outlet, cu.ft/day at stock tank conditions
Qgout=gas flow rate at separator outlet, st.cu.ft/day

Given the actual pressure and temperature at the pump intake (note that the pump intake pressure is not the same as the separator intake pressure due to the pressure drop that exists due to flow through the separator) it is possible to compute the actual liquid percent flowing into the pump accounting for variations of gas and liquid volumes with pressure and temperature.

SEPARATOR PERFORMANCE TESTS IN THE LABORATORY

During the laboratory testing, to be discussed in the following section, measurements were made of the rates of liquid and gas flowing through the separator as a function of:

- Various separator geometric configurations
- Various liquid flow rates
- Various annular gas flow rates

For mixtures of water and air injected through perforations simulating field conditions. In addition, the flow characteristics were visually observed and recorded on video.

DOWNHOLE SEPARATOR TESTING APPARATUS AND PROCEDURE

The system was designed to simulate simultaneous entry of gas and liquid through perforations into a full-size wellbore and to monitor the flow through a downhole separator while making pressure and flow rate measurements and visually observing the performance of the separator. Figure 4 shows a schematic diagram of the closed-loop flow system that was used for all the tests. Visualization of the flow through the perforations is achieved with a 14-foot long, clear acrylic pipe with an internal diameter of 6 inches over which length are distributed ½ inch diameter perforations in a spiral pattern at a spacing of 4 perforations per foot. Above the acrylic casing, is connected a 40-foot high PVC casing, to simulate the upper part of the wellbore, and to establish enough liquid submergence to generate the hydraulic head necessary to obtain the desired flow through the downhole separator system.

The casing perforations are individually connected to a valved manifold to control which perforations are actively injecting fluid during a specific test. This allows changing the relative position between the separator entry ports and the perforations so that tests may be performed with the fluids entering the wellbore at one of three positions: 1) below, 2) above, or 3) at the same level as the separator entry ports.

The downhole separator being tested, is also constructed of clear acrylic pipe and is fixed concentrically inside the casing section by attaching it to a return-flow, 3 inch diameter PVC pipe that exits laterally through the casing via a “T” section. The fluid (air and water) then flows trough the return-flow control valve to the 2-phase separator (4 ft by 10 feet) where gas and liquid are separated. The gas is fed to a metering station and the liquid eventually flows through the pump, back to the mixing section.

At the mixer, water from the pump discharge is mixed with compressed air at a controlled rate and the mixture is fed to the manifold for distribution to the active perforations.

During a specific test, the water rate into the well is controlled the desired value at the centrifugal pump discharge and the return flow control valve is adjusted so as to balance the flow rate through the downhole separator until a stabilized pressure (either 5 or 10 psig) is observed at the bottom of the casing. Then air is admitted to the mixer at the desired rate. After sufficient time has elapsed to achieve a steady state flow through the system, the following measurements are made and recorded:

Gas Rate Injected into the well

The flow of gas into the well is measured by a Fisher & Porter variable area flow meter (model No. 10A4557X). Compressed air is used to simulate the gas in real wells; therefore, the flow meter measures the air rate entering the well. The scale of this flow meter is a percentage, from 0% (0 MCFD) to 100% (16.42 Actual MCFD). In the experiments, four flow rates corresponding to 90%, 60%, 30% and 10% are used. The flow rate is measured at the pressure of the meter that is read using a Daniel absolute pressure transducer and then converted to standard conditions.

Liquid Rate Injected into the well

The flow meter used to read the rate of liquid injected into the well is a Floco (Model No ITT Barton 308K), positive displacement meter for which each revolution of the needle represents 0.1bbl. The liquid rates used for this project are from 100 to 750 bbl/day.

Pressure Measurements

As indicated on Figure 4, pressures were measured at three points in the system:

Casing Pressure (Pc)

The pressure at the bottom of the casing is used as an indication of stable flow conditions. For these experiments, the pressure in the casing was controlled at two average values of 5 and 10 psi at stable conditions. The pressure level was limited by the height (40 feet) of the casing riser that was available to contain the gaseous liquid column in the well at the largest gas rate of 118.70 MSCFD without overflowing.

Ports Pressure (P1)

This is the pressure in the casing at the point opposite the entry ports in the separator.

Separator Exit Pressure (P2)

This pressure corresponds to the pump intake pressure (if a downhole pump were present) and is measured using a pressure/vacuum gage, in psig for positive values and in inches of Mercury for negative values (vacuum). This pressure is used to calculate the pressure drop through the separator system in conjunction with the ports pressure (P1). Pressure drop in the system depends on the geometry of the dip tube. For a small dip tube diameter, the pressure drop is high and for a large dip tube diameter the pressure drop is low.

Gas Rate Flowing Through Gas Separator

The flow rate of the gas (air) that is not separated by the separator and is produced with the liquid (water) is measured at the outlet of the 2-phase separator using one of three flow meters each covering different ranges:

- OMEGA FL-3820C (0-150 mm) from 0 to 63 SCFD
- OMEGA FL-3839ST (0-150 mm) from 0 to 886 SCFD
- OMEGA FL 50000 (0-4.5 inches) from 0 to 6480 SCFD.

The data acquired during one series of tests is saved in a spreadsheet to calculate test parameters such as superficial liquid velocity in the separator, superficial liquid velocity and superficial gas velocity in casing, and the gas rate through the separator.

Other Factors

The ability to separate gas is also related to the size of the bubbles. Gas bubble size is a function of the pressure, gas/liquid interfacial tension, fluid viscosity and the rate of coalescence.

Presentation Of Test Results

To visualize the large number of data that have been collected and to compare the performance of various separator designs and configurations it was decided that graphical representation of the data would provide the most direct method of analysis.

The performance of the separator can be defined in terms of the volume of gas that flows through the separator. For a given geometry and position of the separator relative to the casing perforations, the throughput gas rate depends on the liquid flow velocity inside the separator and of the flow conditions present at the separator inlet ports. For this reason it was decided to present the data in the form of a 3-D graph, as shown in Figure 5. The vertical axis represents the separator throughput gas flow rate (MSCF/D), the X axis represents the Superficial Liquid Velocity (inch/sec) inside the separator and the Y axis represents the Superficial Gas Velocity (inch/sec) in the casing-tubing annulus at the pressure that exists opposite the entry ports of the separator.

Note that these superficial velocities are defined (as is customary in 2-phase flow studies) as the actual (in-situ) volumetric rate of the specific fluid divided by the total cross-sectional area through which it flows (neglecting the presence of the other fluid). As such, they are proportional to the physical velocity of the phases.

Table 1 summarizes the range of values of the gas and liquid flow rates used in the tests. The liquid rate varied from 81 Bbl/day to 755 Bbl/day and the gas flow rate from 9 to 119 MSCF/D. Figures 6 and 7 show the relationship between these flow rates and the superficial liquid and gas velocities in the separator and the casing annulus.

Table 2 illustrates results from a typical test and summarizes the measured flow rates corresponding to one of the series of tests for one specific separator configuration. It also indicates that the sequence of the measurements progressed starting with high liquid and gas rates, then the gas rate was reduced keeping the liquid rate constant (Tests 1 through 4) then the liquid rate was reduced while the gas rate was increased then reduced (Tests 5 and 6). All the data recorded in this study are included in Reference 1.

Figure 5, is a graphical presentation of the data in Table 2 where the flow rate of gas flowing through the separator (MSCF/D) is plotted on the vertical axis (Z) as a function of the superficial liquid velocity inside the separator (X) and the superficial gas velocity in the casing annulus (Y), both in inch/sec. The annotated numbers indicate the sequence of the tests. The general shape of the surface indicates that at a given gas flow rate in the casing annulus, the volume of gas flowing through the separator is practically zero until the liquid velocity in the separator reaches a threshold value, then as the liquid rate increases the gas flow through the separator increases rapidly. The liquid velocity threshold value is indicated on the graph as the green curve on the XY plane. This line is also defined as the "Zero Gas Flow Boundary" for a given separator and it appears to exhibit a hyperbolic form: the optimum liquid velocity decreases as the superficial gas velocity in the annulus increases.

The overall gas flow 3D surface can be used to determine the liquid fraction leaving the separator (entering the pump intake in a field installation) as illustrated by the following calculation based on test point No 4:

Gas rate flowing in casing annulus = 13.4 MSCF/D
Gas rate flowing through the separator = 0.61 MSCF/D
Liquid Rate flowing through separator = 549 Bbl/D = 3085 cu.ft. /D

If the pressure loss through the separator is negligible, the pressure at the separator outlet is equal to the pressure at the entry ports, in this case equal to 10 psig.

Gas volumetric rate at separator pressure = 0.61*14.7/24.7 = 363 cu.ft. /D
Liquid fraction leaving separator = 3085 / (3085+363) = 0.89

This indicates that if the pressure at the pump intake were also 10 psig, the liquid fillage of the pump would be 89%. Note that this value would be different for different values of the pump intake pressure. The lower the pump intake pressure the lower will be the liquid fraction or the gas fraction will be higher, as shown in Figure 8 that shows the same data in Figure 5 converted to gas fraction at different pressures.

On the other hand if one were to express this performance in terms of separator efficiency, as defined earlier, the result would be:

$$Qgs = (13400 - 610)*(14.7/24.7) = 7611 \text{ actual cu. ft./D}$$
$$Qgt = 13400*(14.7/24.7) = 7975 \text{ actual cu. ft./D}$$

$$Es = Qgs/Qgt = 7611/7975= 0.955$$

Indicating the separation efficiency is better than 95%. Note that this value is higher than the liquid fillage for a PIP= 10 psig and that it is independent of the conditions at the pump intake. For this reason, the liquid fraction at the separator outlet should be used in defining the performance of the downhole separator.

Geometry of Separators Tested

Two basic geometries of downhole gas separators were tested that principally differed in the size, shape and disposition of the entry ports.

Figure 9 shows the design of the basic Patterson Model downhole gas separator. It is a 6-foot clear acrylic pipe (item 2) with a diameter of 3 inches OD and 2.750 inches ID. It has eight anchor ports 8 inches long and the width was varied from 1/8” inch to 1/2” in eights of an inch increments. In the upper part, there are four holes of 1/2” diameter. These holes allow the gas to escape from the separator. Inside the separator, there is a dip tube. Two dip tube diameters, 1 inch and 1 ½ inch OD were used.

Figure 10 shows the design of the Echometer Model downhole gas separator. It is a 6-foot clear acrylic pipe (item 2) with a diameter of 3 inches OD and 2.750 inches ID. It has four ports (4 inches long and 2 inches wide). Inside the anchor, there are a dip tube Two dip tube diameters, 1” and 1 ½ “OD were used.

Testing Program

The study consisted of the following series of tests with the objective to study:

1. Effect of the position of the anchor ports relative to the casing perforations: above, in-line and below.
2. Effect of the width of the anchor ports on separator performance
3. Effect of multiple rows of ports on separator performance
4. Effect of the diameter of the dip tube on separator performance and pressure drop.

For each series of tests, the performance of the separator was also documented by video recording the flow in the separator as well as in the wellbore. Figure 11 shows still images of the dip tube inside the separator for the testing sequence discussed in Figure 5, showing the flow of a relatively large number of gas bubbles into the dip tube for test point No. 4 and the almost total absence of gas bubbles corresponding to the conditions for test point No.6.

DISCUSSION OF LABORATORY RESULTS

Although this is a work in progress and this paper is the first of several that will be presented in the future, the following are the primary results to date of the testing:

Position of Anchor Ports Relative to Casing Perforations

For all the geometries of the separator that were tested, whenever the separator ports were located below the casing perforations the amount of gas at the exit of the separator was essentially un-measurable. Even at the maximum liquid rate tested of 750 Bbl/day, corresponding to a liquid velocity in the separator of 20 inches/second and a liquid superficial velocity in the casing annulus of only 4 inches per second. Visual observation of the entrance to the dip tube showed that some very small bubbles were entrained by the liquid, similar to what is shown in Figure 5 for test point 6, so that the liquid fraction leaving the separator was probably above 0.99. This further corroborates the known fact that "***The first choice in gas separation should always be providing a sump below the lowest producing interval***." Reference 1

The important new information is that in all these tests the distance between the lowest casing perforation and the separator entry ports was only about 1.5 feet. This offset was sufficient to allow most of the gas entering through the perforations to flow upwards into the upper annulus and mostly liquid to flow downwards towards the separator ports. This fact should be considered when applying this concept in the field where often the length of the sump or rat hole is minimal and may be considered inadequate to implement a "natural separator" completion. The effectiveness of this completion is also evidenced by the field application in Well 43-26, discussed later in this paper.

When the anchor ports are located above the casing perforations the general trend indicates that the volume of gas flowing through the separator increases as the gas rate into the well and the liquid velocity in the separator increase. See Figure 12 and Figure 13 that summarize all the tests. Notice that for both type separators the guideline of keeping the liquid velocity below 6 inches per second inside the separator does not guarantee good gas separation when the annular gas superficial velocity increases past 7-8 inches per second. When the superficial gas velocity reaches 60 inches per second the rate of gas flowing out of the separator reaches as high as 1.5 MSCFD. In addition, it can be noted that the geometry and number of the entry ports does not seem to have much effect on the performance of the separators since there is not a distinct difference in the results.

When the anchor ports are located opposite the casing perforations the Patterson design with narrow and long ports results in improved performance over the Echometer design that uses larger ports, as seen in Figure 14 and Figure 15. The maximum gas rate through the Patterson separators is 0.16 MSCFD, while the maximum gas rate through the Echometer separators tested is 1.0 MSCFD. These results are somewhat tentative for two reasons: 1) due to the difference in separator construction and the fixed location of the casing perforations, it was not possible to control the relative position of the ports and the perforations so that all tests had exactly the same configuration. 2) It was not possible to repeat exactly, from test sequence to test sequence, the gas/liquid ratio flowing through a specific perforation. Further testing needs to be undertaken trying to achieve more strictly comparable test conditions.
The overall trend however indicates that there is a beneficial effect of using narrow ports when there is a good probability that the separator entry ports may be located where the flow from perforations may impinge directly onto the separator ports. The vent hole baffle used in the Patterson design, thought to provide a low-pressure vent for gas accumulation in the gas separator, has not been tested in the laboratory. Figure 16 has a drawing for separator intake below perforations, in the perforations and above perforations.

Geometry of Anchor Ports

The effect of separator anchor port width was studied in this project for the Patterson models by increasing the anchor port width while keeping constant the length and location of the anchor ports:

- Patterson 1 => anchor ports = 8" x 1/8" & dip tube = 1"
- Patterson 2 => anchor ports = 8" x 1/4" & dip tube = 1"
- Patterson 3 => anchor ports = 8" x 1/2" & dip tube = 1"
- Patterson 4 => anchor ports = 8" x 3/4" & dip tube = 1"

Increasing the width of the anchor port from 1/8 to 3/4 inches, the total cross-sectional area of anchor ports (each separator has eight anchor ports) increases from 8 to 48 square inches and the liquid velocity in the anchor ports decreases. For example, for a liquid rate Q (Bbl/D), the liquid velocity for Patterson 1 is 0.0281Q inches/second, and for Patterson 4 is 0.0047Q inches/second. When the casing perforations are opposite the anchor ports, Figure 14 shows that the trend indicates that increasing the port width from 1/8 inch to 1/4 inch reduces the gas flow through the separator but additional benefit is not observed when increasing to ½ or ¾ inch

In Figure 12, it is noticed that, when the anchor ports are located above the casing perforations, increasing the anchor port width, does not affect the performance and the gas rate through the separator is almost the same for all of the Patterson models.

Effect of Multiple Rows of Ports

Figure 16 illustrate graphically the results of video observation of the fluid flow path for the three configurations of relative position of the anchor ports and casing perforations. All the separators tested included two rows of entry ports. In all the three cases, it was clearly seen that most of the liquid entered the separator through the bottom row of ports. At this point, there exists a boundary between the flowing fluid and either a stagnant section of fluid or a section of fluid where there is zero net liquid flow (only the gas is flowing upwards, the liquid re-circulates). Based on these observations it was concluded that the performance of these separators would not be affected by closing of the upper row of ports (but leaving vent holes for the gas). The Patterson 7 separator and the Echometer 3 were tested and as seen in Figures 12 through 15 their performance is similar to that of the separators with double rows of ports.

Effect of Dip Tube Diameter

The most important parameter affecting separator efficiency is the liquid superficial velocity in the separator Vl that for a constant rate can varies when changing the dip tube diameter for a constant ID of the separator
It was observed that when the dip tube diameter is changed, the Echometer and Patterson models exhibit the same behavior. In general, it was observed that when the separator ports are located opposite the perforations the flow rate of gas exiting the separator increases as the dip tube diameter is increased even at the same superficial liquid velocity. This can be observed in the pictures of the entrance of the dip tube shown in Figure 17 A that show that the fraction of gas is much greater for the 1.5 inch diameter dip tube, for equivalent tests of the same type separator.
On the other hand, when the separator ports are located above the casing perforations the performance of the separator s independent of the diameter of the dip tube when the same superficial fluid velocities are maintained. Figure 17B that shows about the same fraction of gas for the two cases.

The other important effect of the diameter of the dip tube is on the pressure drop through the separator as presented in Tables 3A and 3B that show the measured and calculated pressure drops through the separator, for 100 % liquid flow. There is about a five-fold increase of pressure drop when decreasing the dip tube ID from 1.28 inch to 0.75 inch, as the OD of the dip tube is decreased. Excessive pressure drop through the separator will cause increase of the gas fraction of the fluid exiting the separator. Considering that the overall length of the dip tube is only 5.5 feet, it is recommended that in field applications the length of the dip tube be kept at a minimum.

FIELD PERFORMANCE OF SEPARATORS TESTED

Patterson Type Separators

Results of limited field-testing[1] of gas separators used with progressing cavity pumps presented in detail at the SWPSC showed improved gas separation with the pump set in the producing interval in Power River Basin Coal Bed Methane wells. Standard practice is to initially run a pump without a gas anchor since 12 to 18 months of water production are required before significant gas production. Gas that is not separated downhole is produced up the tubing and is subsequently vented from the produced water tanks. Some wells have significant gas, 30 to 100 MCFD, coming up the tubing. Wells that have gas separation problems tend to be in the initial dewatering period producing high water rates and have high bottom hole pressure.

Well 43-26

Well 43-26 is a 7" completion with a 14" under reamed open hole as shown in Figure 18A.

Initially the 5 ½" gas separator design had:

- Inlet area of 15.0 in^2 and 16.84 in^2 cross sectional area
- Inlet slots were 3/16" wide by 10"
- Three ½" vent holes in the swedge above the mud anchor

The inlet velocity (0.27 to 0.22 ft/sec) and downward velocity (0.24 to 0.19 ft/sec) were calculated with turbine meter water rates. There was essentially NO gas up the tubing. But after 47 days the PCP was pulled due to high torque and found the bottom of the 5 ½" mud anchor full of solids which bridged across the 1.75" gas anchor starving the pump. The same installation was run with the intake just below the 7" casing shoe moving the pump intake to 1344'. The test data and performance was similar to the pervious performance of the 5-½" gas separator set 30' deeper. After 46 days of production the 5 ½" gas separator plugged again and it was decided to run the slotted liner.

For installation #6 - due to plugging of the gas separator by coal fines, a 5 ½"slotted liner was run with the bottom 20 feet being blank pipe which allowed the pump intake to be "sumped" or placed below the bottom slot of the liner. The intake was at 1446' or 14 feet below the bottom of the slots in the liner.

As shown in detail in the production graphs and the tabulated data in the original paper (Reference 1), sumping the pump in the blank section of the liner made a significant difference in the gas rate and water production. Well 43-26 illustrates that well construction can improve gas separation and supports the "age old theory" that placing the intake to the pump below the perforated interval creates an effective natural gas anchor. The addition of a 20' blank section on the bottom of the slotted liner created the necessary sump. ***The first choice in gas separation should always be providing a sump below the lowest producing interval***.

Well 24R-24

Well 24R-24 is a 7" completion with a 14" under reamed open hole with a 5-½" slotted liner as shown in Figure 18B installation schematic. This well was originally a 7" completion with an under reamed open hole with a scab line set across a shale. When the 5-½" slotted liner was run it was set on top of the scab liner. There is an offset between the scab liner and the bottom of the slotted liner so than the pumps cannot be set in the scab liner.

The field-tested separator was similar to the Patterson 3 laboratory test design:

- The OD of the separator was 4". The slots were 3/16" wide by 8" long.
- Three vent holes were drilled on a 2 7/8" nipple and were covered with a 4" OD baffle.

For installation No 4, the separator was tested for a period of four months (9/6 2002 to1/1/2003) Physical observation indicated essentially gas free water produced up the tubing.
Pump efficiency based on actual water rate and pump RPM, initially was 130% and was maintained above 85% in all tests. Efficiencies above 100% were probably due to using an average pump RPM too high and not accounting for the drive speed variation to maintain the intake pressure set point.
For comparison purposes, the test data at 9/16/2002 indicates a gas production rate up the casing of 184 MSCF/D a liquid rate of 174 Bbl/day and no gas production up the tubing. The pump intake pressure was controlled at 100 psi. The 4 inch OD separator was set inside a 5-1/2 inch 15 #/ft slotted liner resulting in an annular area of 6.677 sq. inch. Considering the pump intake pressure of 100 psig the corresponding superficial gas velocity in the annulus is 70.63 inch/second. Inside the separator was installed a 1.75 inch dip tube. For the liquid rate of 174 Bbl/day, the resulting downward superficial liquid velocity is 2.8 inch/sec. These coordinates are used to locate the vertical down arrow on Figure 14 to locate the corresponding conditions on the performance diagram and showing the good field performance of the separator corresponds to what was observed in the lab at the same superficial gas and liquid velocities.

Echometer Type Separators

The following is a discussion of two field tests for the Echometer Gas Separator, one was installed in Vogt 8 and the test was successful, the second was installed in Jones 1 and the gas separator did not seem to perform better than the original Poor Boy Gas Separator.

After installing a pump-off-controller on Vogt 8, the operator was having difficulty in setting the POC to operate properly. A fluid level test, Figure 19, indicated that liquid existed above the pump even though the well was being pumped all of the time. A dynamometer test indicated that the liquid fillage was approximately 30%. When the well was shut down for 10 minutes and then started to pumping, the very first card and each card afterwards showed that the pump was not full. See Figure 20 that shows the first 61 surface cards after the unit started pumping. The surface cards and pump fillage of about 30% did not vary significantly during the test, indicating that the Poor Boy gas separator was inefficient and not separating the free gas in the casing annulus from the liquid.
The sucker rods, pump, and tubing were pulled. The pump had two standing valves and one of the standing valves was removed. The reconditioned pump and an Echometer Gas Separator were run into the well.

The well was tested for pump and gas separator performance. The liquid level test shown in Figure 21 confirms that all of the liquid is being removed from the casing annulus. The well was shut down for ten minutes and then started. Numerous strokes of 100 % liquid fillage were obtained as shown in Figure 22, then pump fillage declined to match the formation inflow production rate as soon as the excess liquid above the gas separator ports was removed. . The Echometer gas separator functioned as desired and separated the free gas from the liquid. This improved gas separation and allowed the well to be pumped approximately 1/3 of the time while obtaining the maximum liquid and gas production from the well. Equipment life was extended and operating costs were reduced because the well did not pound fluid continuously and the well only pumped 1/3 of the day. The full pump liquid displacement (190 Bbl/day) and the annular gas rate (23 MSCF/D) converted to the corresponding superficial velocities (Vsg= 18 inch/sec and Vsl= 7.5 inch/sec) are used to plot the operating point (down arrow) in Figure 13, showing that the separator was operating in the region of low gas fraction.

The Jones1 well produces from two zones: one at 5800ft is low pressure and contains gas; the second lower zone contains gas, oil, and water, and produces mostly liquid. At the time of the liquid level test, shown in Figure 23, the well was producing 25 BOPD, 40 BWPD, and 60 MCF/D. Although the pumping system included a Poor Boy Gas Separator, the well had a high fluid level and a producing bottomhole pressure of 300 psi or 50% of the estimated reservoir pressure of 600 psi. This indicated that the maximum production was not being obtained from the well. The high liquid level in the casing annulus also covered the upper zone and restricted its production. The tubing was not anchored. The bottom-holdown pump had a small hole immediately above the standing valve to allow some liquid to flow from the tubing annulus into the pump when the pressure inside the pump is less than the pressure outside the pump barrel. Thus, some liquid was being circulated back into the pump to increase liquid fillage and to force the traveling valve to open before the bottom of the down stroke. The pump dynamometer card in Figure 24 clearly shows the effect of the small hole in the pump barrel, the movement of the tubing in the well and that liquid fillage is approximately 40%. Even though considerable liquid existed above the Poor Boy gas separator, it did not properly separate the free gas from the liquid, which caused incomplete fillage of the pump.

The well was serviced; the pump replaced with a new pump that did not have a small hole immediately above the standing valve, and an Echometer gas separator was installed. The measured fluid level is shown in Figure 25. The backpressure against the formation is approximately the same as it was with the Poor Boy Gas Separator. The corresponding dynamometer test, shown in Figure 26, indicates that the liquid fillage is approximately the same as with the Poor Boy Gas Separator. Note the more conventional shape of the pump card due to the change in pump design that indicates significant gas compression on the downstroke and expansion on the upstroke. The Echometer Gas Separator did not result in better separation and additional production from the well.

Several samples of the well fluids were collected into a clear cylinder approximately twelve inches tall. Considerable foam existed when the well fluids were discharged into the clear cylinder. The oil contained small bubbles of gas that were released from the liquid over a period of approximating twenty seconds (digital pictures of these samples are available upon request).
The entrapment of the gas bubbles within the oil and the slow movement of these entrapped small gas bubbles indicated that the conventional rule of free gas slipping upward in a liquid column at a speed of 6 inches per second does not always apply. The slow movement of these small bubbles prevented the separation of free gas from liquid downhole. Probably, for some oil compositions, water composition, and hydrocarbon gas properties under certain conditions, the hydrocarbon gas is released from the oil such that the gas bubbles are extremely small and cause unstable foam to exist. The release of gas from water is entirely different then the release of gas from oil since much less gas is dissolved into the water. The release of gas from water due to a pressure drop normally does not cause a foam condition. The separation of free gas from oil is more difficult than the separation of free gas from water. For an approximation, saturated oil will release about ½ cu. ft. /bbl/psi of hydrocarbon gas when pressure is reduced.

The test on this well indicates the behavior of free gas in water is much more predictable than free gas in oil. The rule of using a gas velocity of 6 inches per second is probably a better assumption when the free gas is moving upward through water. However, when gas is released from oil under certain conditions of pressure drop it is released into very small bubbles and forms foam or emulsion that does not separate in a short period. This somewhat stable emulsion or foam greatly reduces the efficiency of a gas separator.

The laboratory studies discussed earlier in this paper were conducted in air and water. The separation of air from water is probably more predictable than the separation of a hydrocarbon gas that is in solution with oil. Additional studies should be conducted in the laboratory using fluids that are more representative of hydrocarbon oil and gases. However, a safety issue exists for testing in a laboratory.

RESULTS AND CONCLUSIONS

The following conclusions and recommendations are based on the previous discussion and the observation of the flow characteristics as illustrated in the photos and the numerous video clips recorded during this study.

1. The best position to place a downhole gas separator is where the slots are below the bottom casing perforations. The distance between the slots and the last perforation needs only to be a few feet. In this position, very little gas will enter the downhole gas separator as long as the downwards-liquid velocity in the annulus is less than the gas bubble rise velocity.
2. The volume of gas flowing through the separator, when it is located with the entry ports at or above the casing perforations, is a function of at least two variables: a) The liquid superficial velocity inside the separator and b) The gas superficial velocity in the annulus between the casing and the separator. As the annular gas superficial velocity increases the liquid superficial velocity inside the separator must decrease in order to maintain high separation efficiency. Increasing the superficial gas velocity in casing increases the flow of gas through the separator for a constant liquid velocity inside the separator.
3. Increasing the slot width decreases the gas rate going through the separator when the fluid is entering in front the slots for the Patterson models up to a slot width of ¼ inch.
4. Pressure drop in the system (between the slots and the entrance to the pump) depends directly on the dip tube internal diameter and length. A long dip tube will generate more pressure loss in the system. The tests indicate that good gas separation was obtained with a 5.5 ft long dip tube.
5. It is not necessary to have a long downhole gas separator; the length of the separators tested of 6 feet (5.5-foot dip tube) resulted in efficient separation.
6. It is observed that when there are gas vent holes at the top of the separator and multiple rows of slots, the upper slots do not contribute to admitting liquid in the separator; therefore, it does not seem necessary to design a downhole gas separator with multiple rows of fluid entry slots.
7. When the separator entry ports are above the casing perforations (the most common position in field installations), all of the separator models tested that have the same dip tube diameter exhibit the same behavior.
8. Limited field-testing of the Patterson gas separators indicate that their performance agrees with the laboratory observations.
9. The Jones 1 field-testing of the Echometer gas separator indicated that performance may have been affected by oil foaming conditions.

FUTURE WORK

This paper is a progress report of an ongoing project. Future work will try to address the following recommendations:

1. The effect of the viscosity of the liquid is thought to be an important parameter; therefore, it is recommended to continue the current project, changing the viscosity of the fluid.
2. The behavior of these separator models at a high gas and liquid rate was studied in detail in this project. It is recommended to run a series of tests controlling liquid and gas velocities to define more accurately the zero gas fraction curve.
3. To study in detail the behavior of the separator when it is located in front of the perforations, it is necessary replicate exactly the position of the slots and their alignment with the perforations. These tests should be repeated.
4. The superficial liquid velocity in the casing is an important factor; therefore, it would be good to change the separator outside diameter (to change the annulus area between the casing and the anchor). Current "rule of thumb" to run the largest mud anchor OD possible inside the casing may not provide the best gas separation.
5. The tests run for this project simulate a continuous flow (Progressing Cavity Pumps). Therefore, to understand the performance of the separator when used with Sucker Rod Pumps, it is necessary to modify the apparatus in order to control the flow intermittently to simulate the fact that in Sucker Rod Pumps there is fluid flowing through the separator only during one half of the stroke. Current "rule of thumb" of 1 to 2 pump volumes of quiet volume may not provide best gas separation.
6. The differences in surface properties of the fluids affect the foaming tendencies. If the well is treated with chemical products or produces certain crude oils, the gas liquid separation may be much slower than for air water mixtures. Lab tests with small surfactant concentrations should be undertaken to simulate these effects.
7. Conduct the air/water evaluations at higher static pressures (50 psi) to study the impact of smaller bubble size on the performance of the gas separators.

REFERENCES

(1) Patterson, J.C. – Leonard, N.: "Gas Anchor Design Changes Used to Improve Gas Separation in Coal bed Methane Operations in Wyoming" Proc. 50th Annual Southwestern Petroleum Short Course, Lubbock, Texas, 2003, 136-147.

(2) Lisigurski, Omar: "The effect of geometry on the efficiency of down hole gas separator" MS Thesis, University of Texas at Austin, December 2004.
http://www.pge.utexas.edu/theses04/lisigurski.pdf

Table 1
Range of Liquid and Gas Rates for All Tests

SEPARATOR MODEL	Maximum Liquid Rate BBD	Minimum Liquid Rate BBD	Maximum Superficial Liquid Velocity in Separator inches/second	Minimum Superficial Liquid Velocity in Separator inches/second	Maximum Gas Rate MSCFD	Minimum Gas Rate MSCFD
PATTERSON 1	716.42	81.85	15.62	1.78	118.70	9.02
PATTERSON 2	726.66	100.63	15.84	2.19	112.40	13.35
PATTERSON 3	702.44	142.08	15.31	3.10	112.40	12.18
PATTERSON 4	714.05	114.65	15.57	2.50	114.41	13.26
PATTERSON 5	701.30	118.89	18.86	3.20	110.93	13.43
PATTERSON 6	755.91	103.75	20.33	2.79	111.02	13.47
PATTERSON 7	689.55	117.15	15.03	2.55	112.58	13.51
ECHOMETER 1	658.54	95.46	14.36	2.08	113.45	13.49
ECHOMETER 2	675.53	108.53	18.17	2.92	113.62	12.77
ECHOMETER 3	740.36	104.10	16.14	2.27	113.10	13.04
BUCKET	744.83	127.06	20.04	3.42	116.05	13.44

Table 2
Sample Data for the Test Sequence Corresponding to Figure 7

SEPARATOR TYPE: Patterson 1
OD DIP TUBE= 1"
NUMBER OF SLOTS=8
DIMENSIONS OF THE SLOTS=8" x 1/8"
FLUID ENTERING BELOW THE ANCHOR PORTS, Pc = 10 psig

Test N°	Perforations Liquid Rate Bbl/day	Perforations Gas Rate MSCF/D	Superficial Liquid Velocity in Separator	Superficial Liquid Velocity in Casing	Superficial Gas Velocity in Casing	Gas Rate through Separator MSCF/D
			Inches/sec	Inches/sec	Inches/sec	
1	552.4	108.6	12.0	2.9	55.8	0.6281
2	571.8	75.7	12.5	3.0	38.5	0.9360
3	553.5	39.4	12.1	2.9	20.3	0.7238
4	549.3	13.4	12.0	2.9	6.8	0.6102
5	274.9	118.2	6.0	1.5	60.7	0.0000
6	276.3	76.3	6.0	1.5	40.1	0.0000

Table 3
Measured and Calculated Pressure Drops through Separator for 100% Water Flow,
5.5-foot Long Dip Tubes

Dip tube OD = 1.0 inch, ID= 0.75 inch

Floco Meter	Q	Pc	P1	P2		Delta P	P2 (calculated)	Delta P
(sec/0.1BBl)	bbd	psi	psi	"Hg	psi	(P1-P2)	psi	(P1-P2)
12.30	702.44	10.5	7.8		2.8	5.0	1.87	5.9
12.99	665.13	9.8	7		2.5	4.5	1.55	5.4
14.67	588.96	9.9	7.2		2.6	4.6	2.66	4.5
18.25	473.42	10	7.3		3.8	3.5	3.96	3.3
29.06	297.32	10.7	8.1		5.6	2.5	6.16	1.9
31.42	274.98	10.5	8		5.2	2.8	6.20	1.8
55.24	156.41	10	7.3		6.0	1.3	6.09	1.2

Dip Tube OD = 1.5 inch, ID = 1.28 inch

Floco Meter	Q	Pc	P1	P2		Delta P	P2 (calculated)	Delta P
(sec/0.1BBl)	bbd	psi	psi	"Hg	psi	(P1-P2)	psi	(P1-P2)
13.36	646.71	10.0	6.8		5.4	1.4	5.55	1.3
14.36	601.67	10.0	6.9		5.6	1.3	5.70	1.2
16.30	530.06	10.0	6.9		5.7	1.2	5.77	1.1
23.25	371.61	10.1	7.0		5.9	1.1	5.99	1.0
35.48	243.52	10.1	6.9		5.9	1.0	5.97	0.9
68.67	125.82	10.0	6.8		5.9	0.9	5.91	0.9

Natural Gas Anchor - Pump Intake Below Bottom Perfs

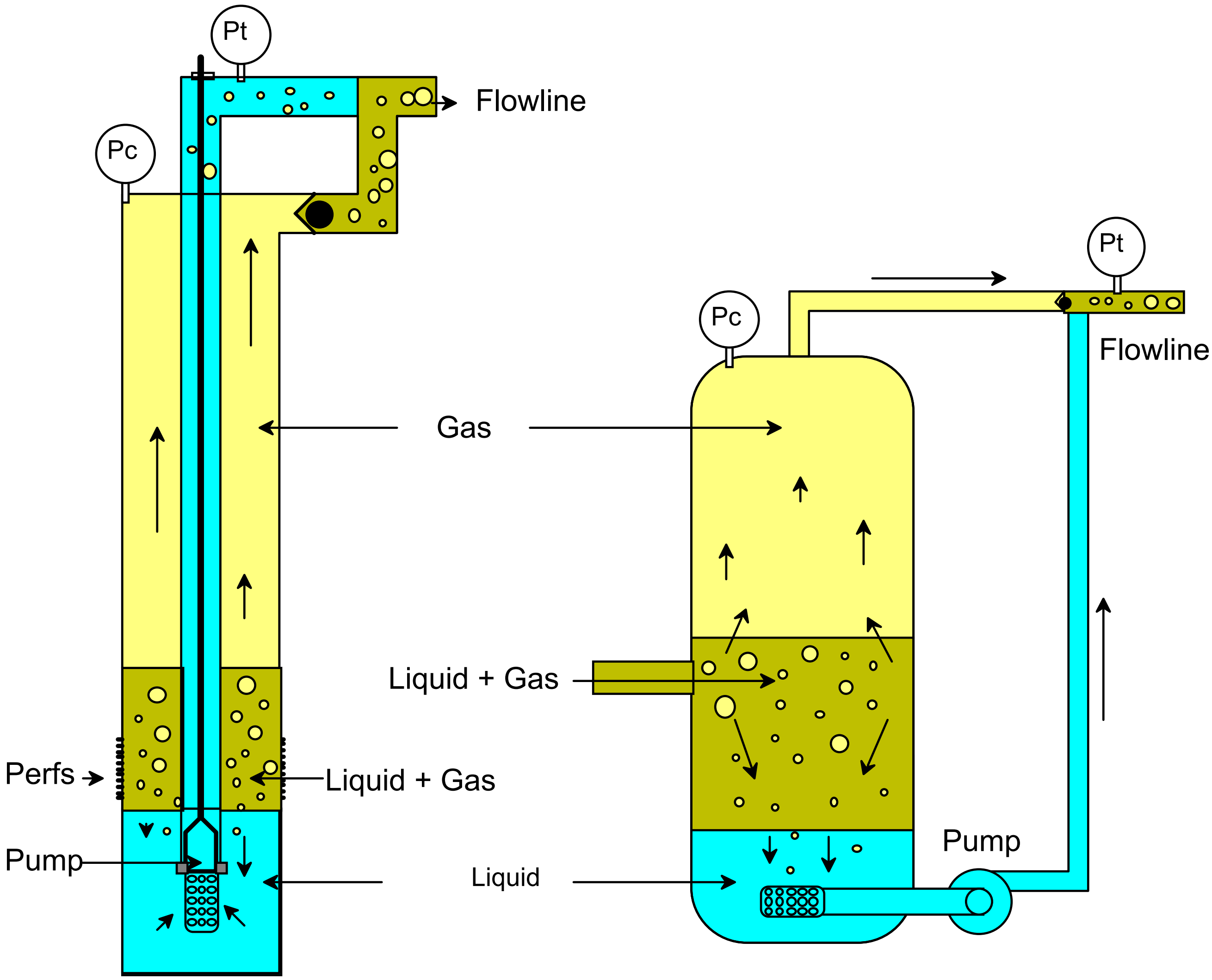


Fig 1A -Wellbore

Fig 1B -Equivalent 5 inch Diameter Two-Phase Separator

5-1/2 inch Casing
2-3/8 inch Tubing

Absence of level control and back-pressure regulator implies the possibility of liquid carry-over or gas entering the pump intake.

"Backwards Separator" - Pump Intake Above Top Perfs

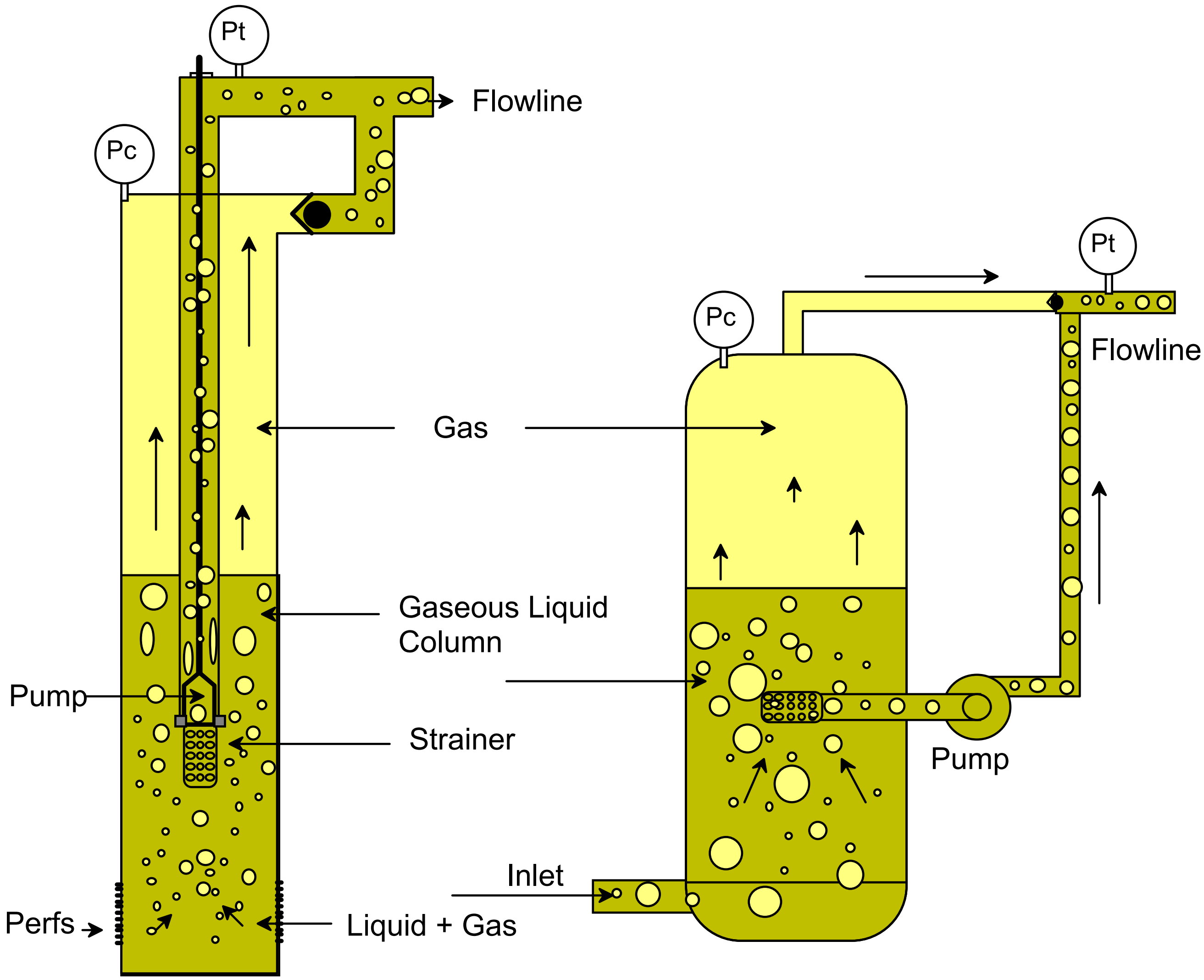


Fig 2A - Wellbore

Fig 2B - Equivalent 5 inch Diameter
Two-Phase Separator

5-1/2 inch Casing
2-3/8 inch Tubing

Gas present at the pump intake enters the pump and reduces pump efficiency. No level control.

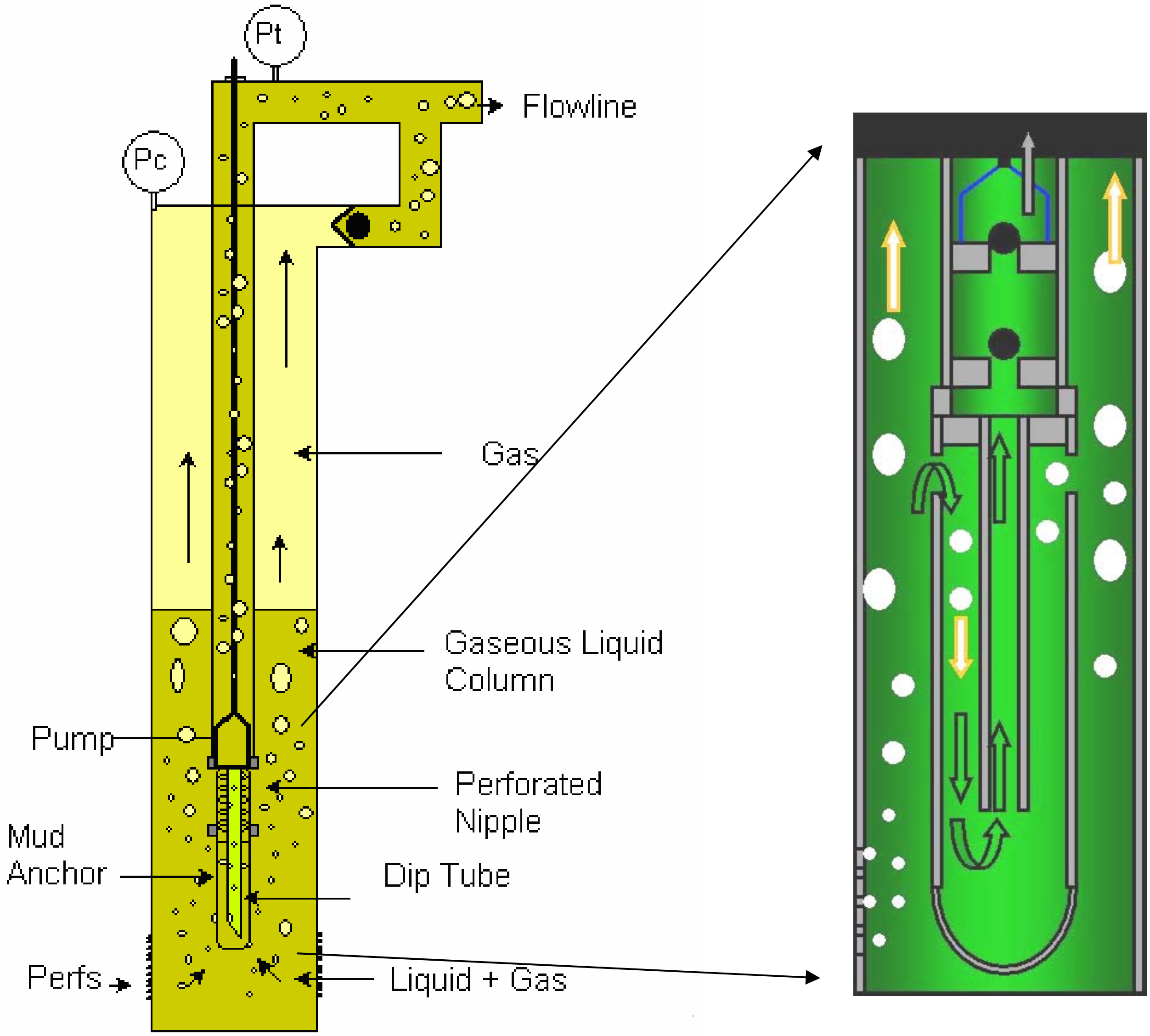


Figure 3 – The 2-stage, “Separator within Separator” Wellbore Configuration

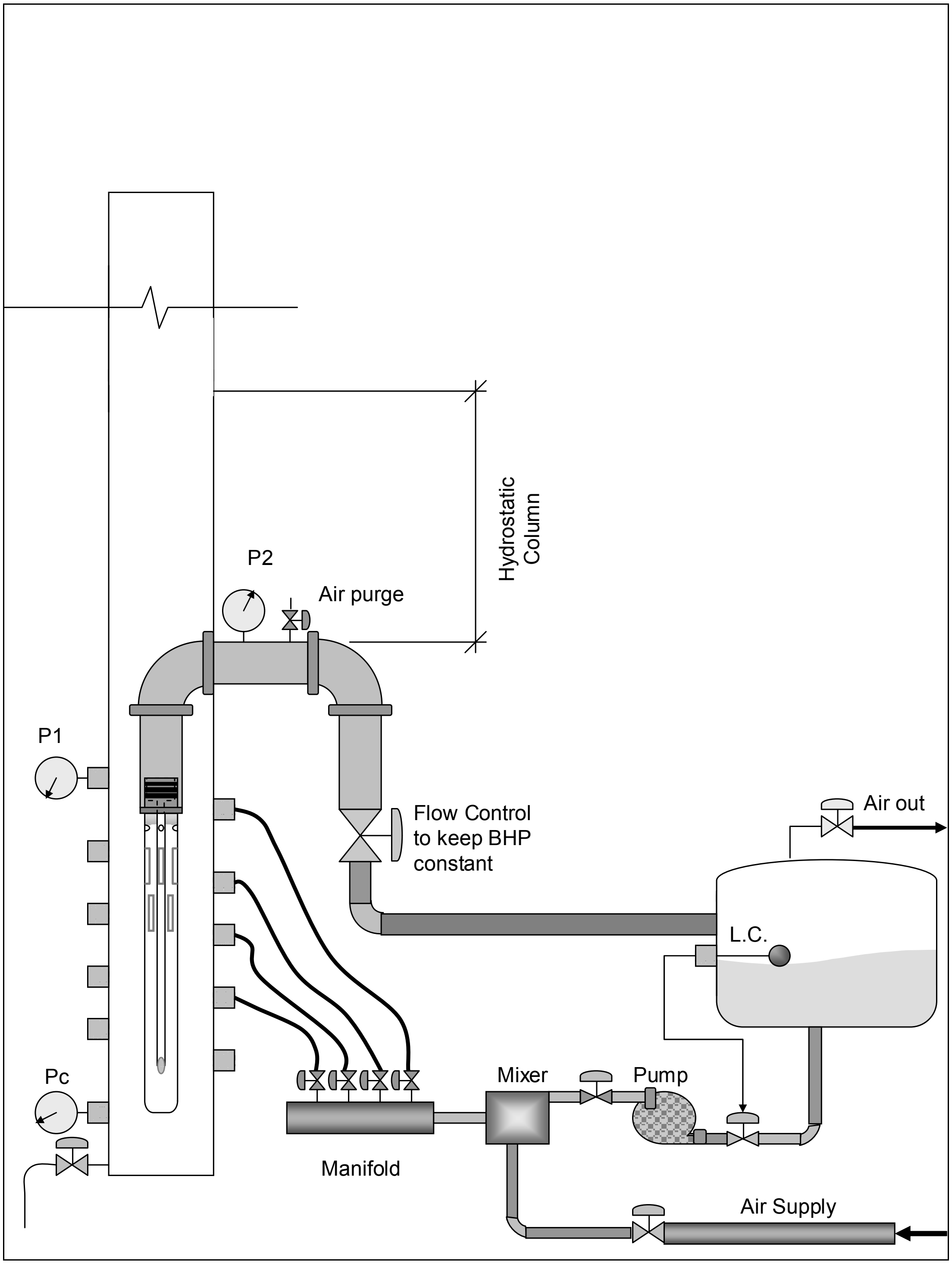


Figure 4 – Schematic Diagram of Experimental Apparatus

SEPARATOR TYPE: **PATTERSON** **1**
OD DIP TUBE = **1”** NUMBER OF SLOTS =**8** Pc = **10 psi**
DIMENSIONS OF THE SLOTS =**8" x 1/8"**
POSITION OF THE SEPARATOR ENTRY PORTS = **ABOVE THE CASING PERFORATIONS**

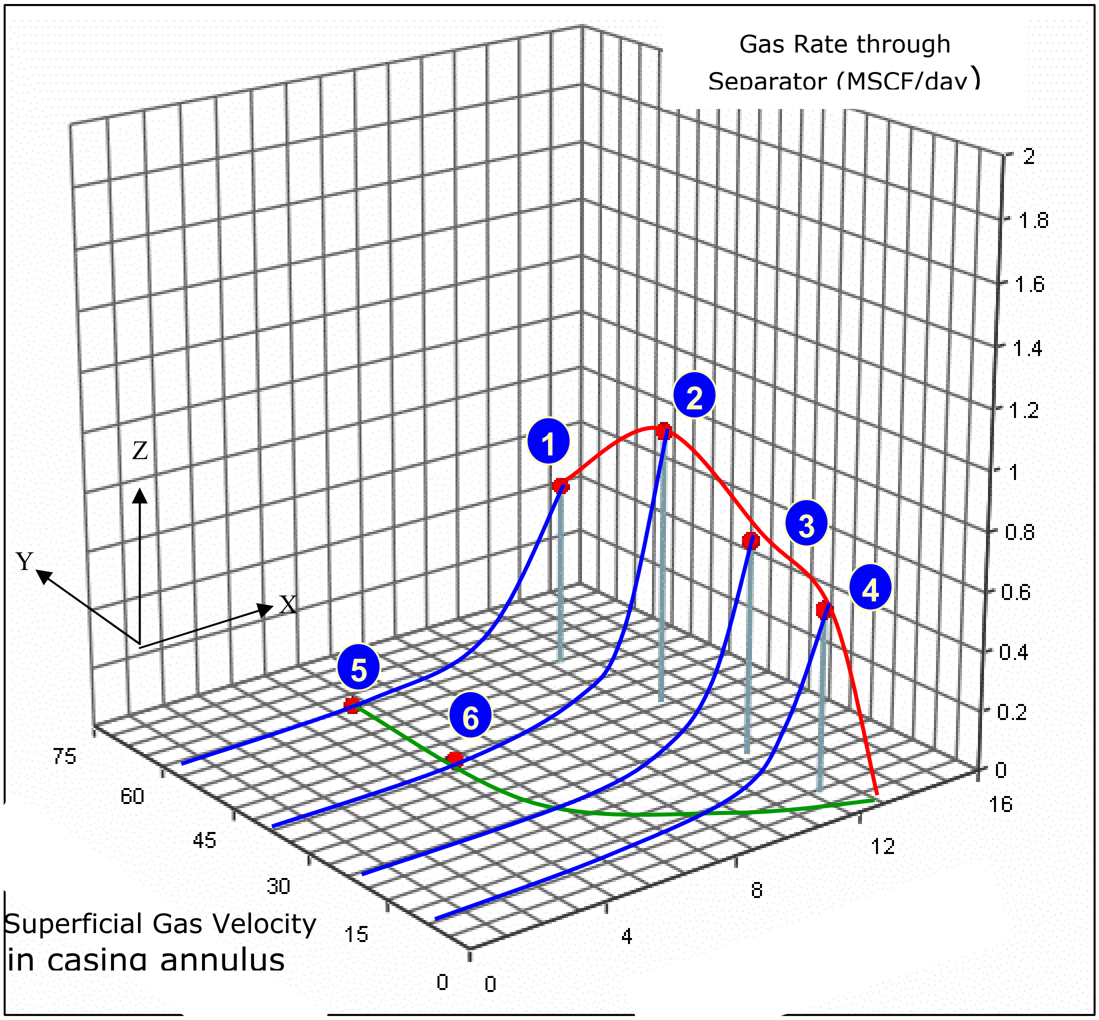


Figure 5 – Typical Presentation of Results of Measured Gas Flow Rate at Separator Outlet. Numbers indicate the sequence of test measurements

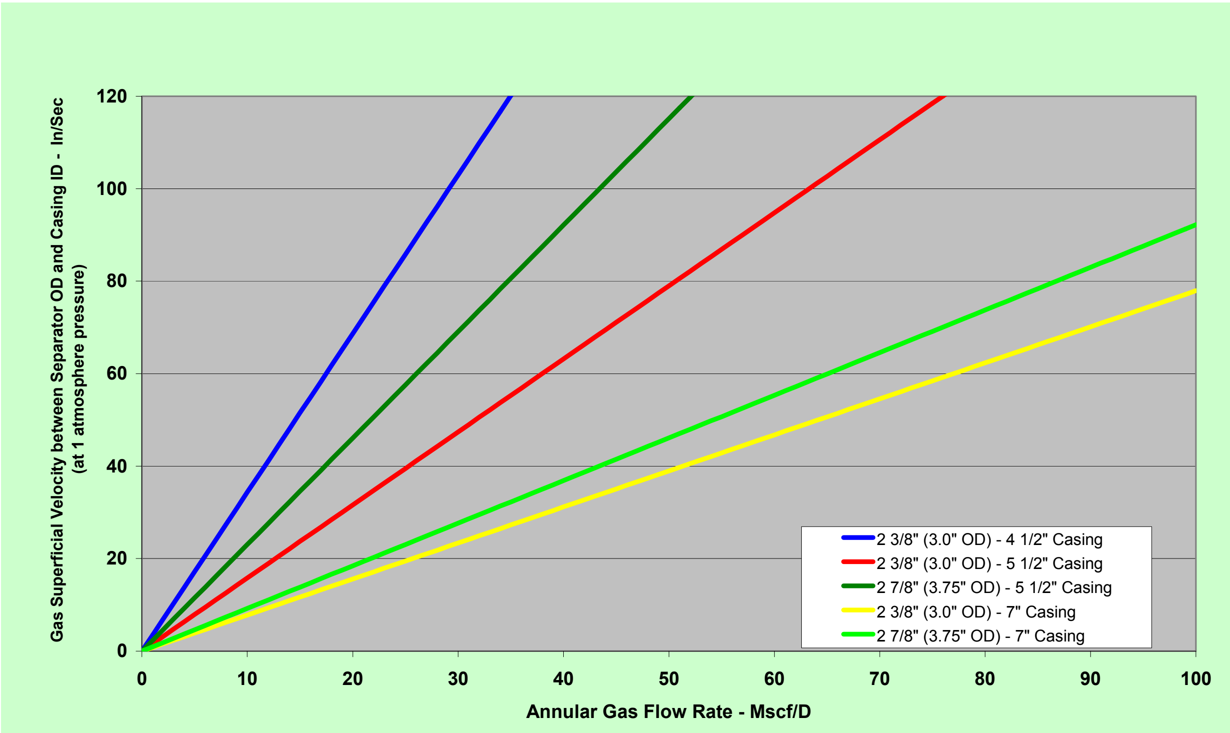


Figure 6 – Gas Superficial Velocity (inch/second at 1 atm. pressure) as a Function of Gas Flow Rate (MSCF/D) for Various Casing-Tubing Diameter Combinations

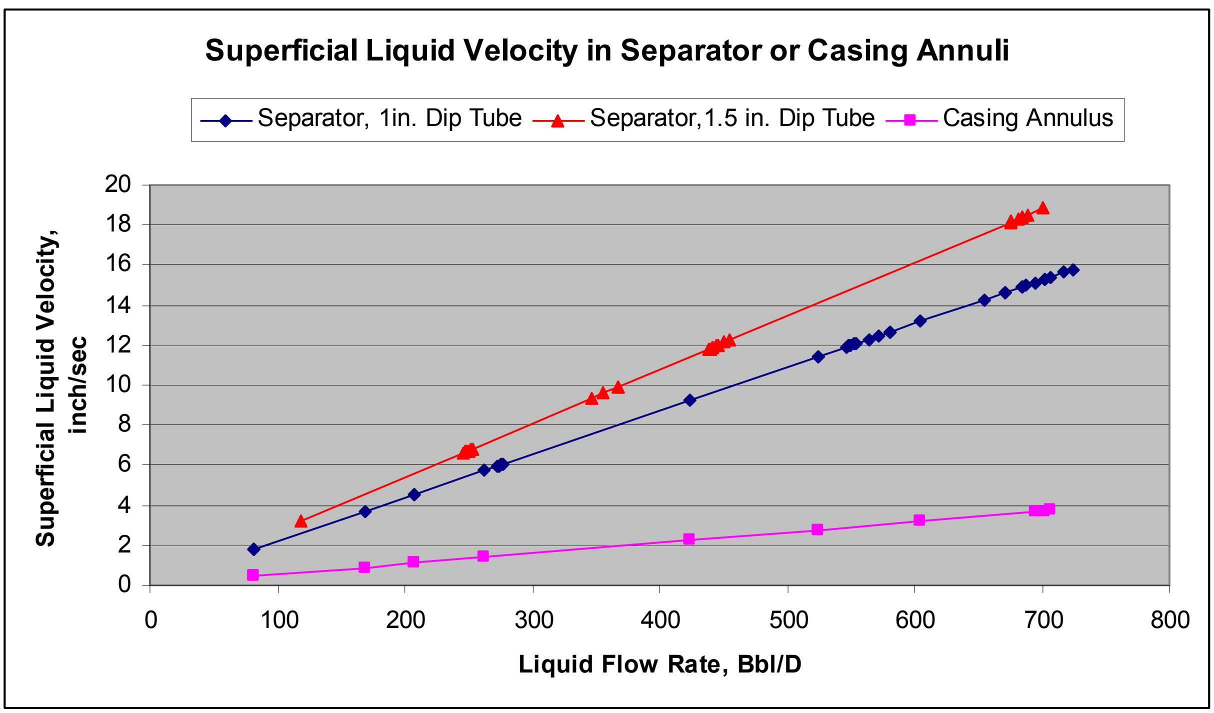


Figure 7 – Superficial Liquid Velocity in Separator and in Casing Annuli for Various Flow Rates

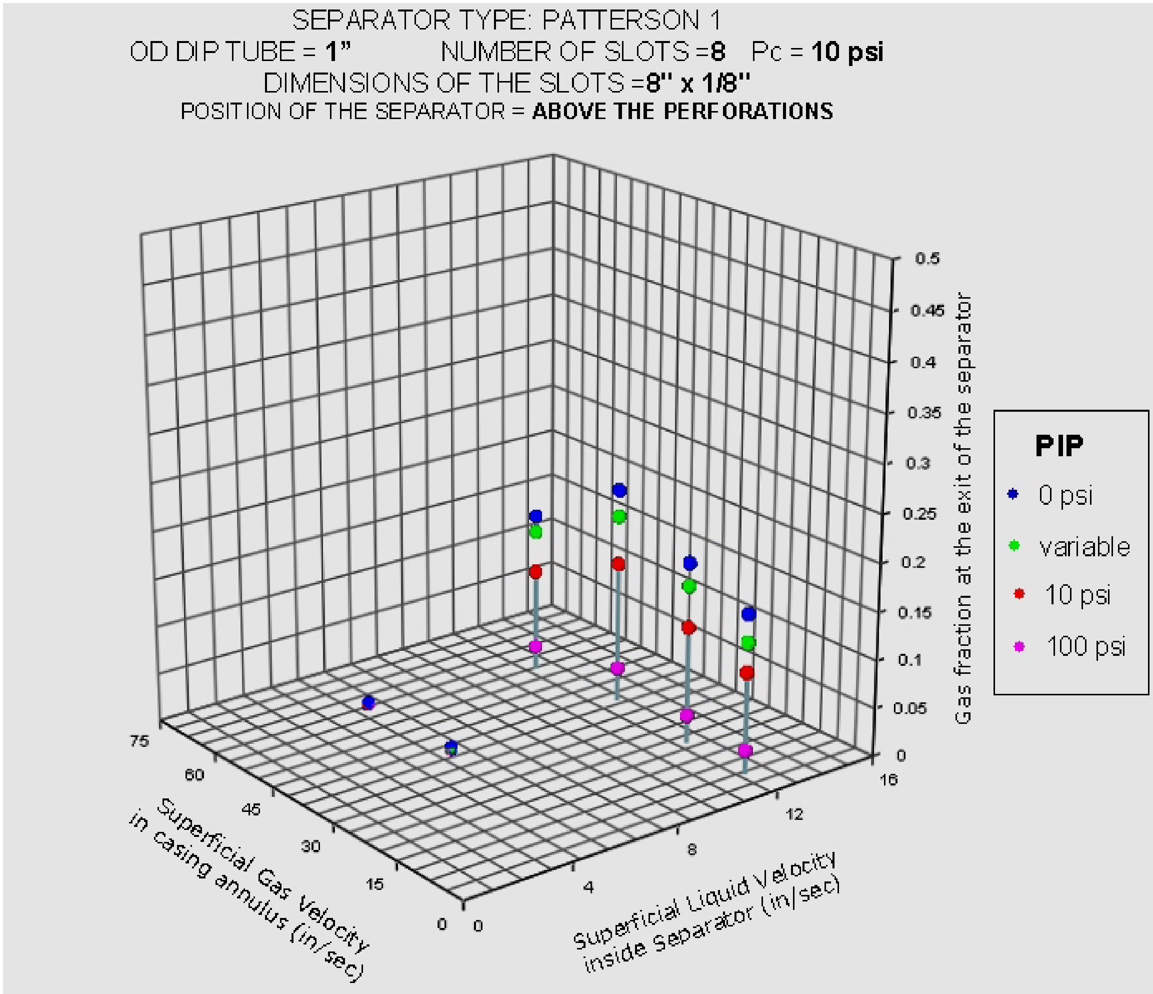


Figure 8 – Gas Fraction at Separator Exit for Pump Intake Pressures of 0, 10 and 100 psig.

GAS ANCHOR		
OD	3.000	inches
ID	2.750	inches
OD Area	7.069	inch^2
	0.049	ft^2
ID Area	5.940	inch^2
	0.041	ft^2

HOLES		
Number of holes	4.000	
ID	0.500	inches
Area of each hole	0.196	inch^2
	0.001	ft^2
Total Area	0.785	inch^2
	0.005	ft^2

SLOTS		
Number of holes	8.000	
Longitude	8.000	inches
Width	0.125	inches
Area of each slot	1.000	inch^2
	0.007	ft^2
Total Area	8.000	inch^2
	0.056	ft^2

DIP TUBE INSIDE THE ANCHOR		
OD	1.000	inches
ID	0.750	inches
OD Area	0.785	inch^2
	0.005	ft^2
ID Area	0.442	inch^2
	0.003	ft^2

CASING		
ID	6.000	inches
ID Area	28.274	inch^2
	0.196	ft^2

ANNULAR AREA		
Anchor/Dip Tube	5.154	inch^2
	0.036	ft^2
Casing-Anchor	21.206	inch^2
	0.147	ft^2

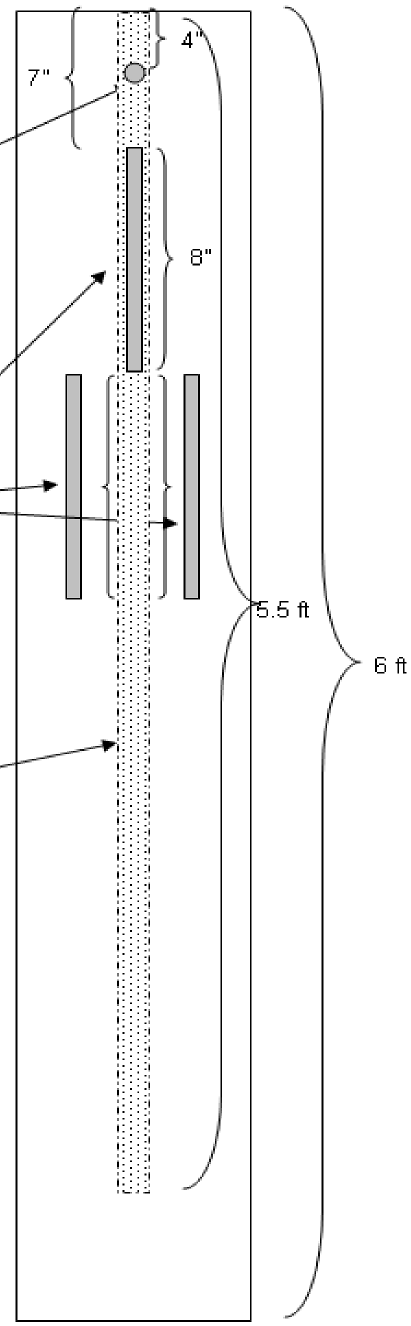


Figure 9 – Construction Details Patterson Type Separators

DOWNHOLE GAS SEPARATOR

GAS ANCHOR		
OD	3.000	inches
ID	2.750	inches
OD Area	7.069	inch^2
	0.049	ft^2
ID Area	5.940	inch^2
	0.041	ft^2

SLOTS		
Number of holes	4.000	
Longitude	4.000	inches
Width	2.000	inches
Area of each slot	8.000	inch^2
	0.056	ft^2
Total Area	32.000	inch^2
	0.222	ft^2

DIP TUBE INSIDE THE ANCHOR		
OD	1.000	inches
ID	0.750	inches
OD Area	0.785	inch^2
	0.005	ft^2
ID Area	0.442	inch^2
	0.003	ft^2

CASING		
ID	6.000	inches
ID Area	28.274	inch^2
	0.196	ft^2

ANNULAR AREA		
Anchor/Dip Tube	5.154	inch^2
	0.036	ft^2
Casing-Anchor	21.206	inch^2
	0.147	ft^2

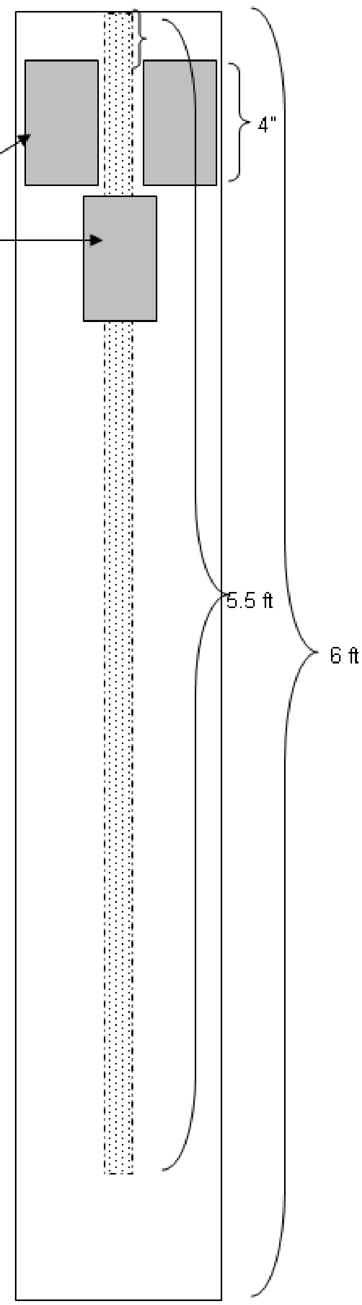


Figure 10 – Construction Details, Echometer Type Separators

Test Point No 4
Separator Vsl=12 inch/sec (550 B/D); Casing Vsg=6.84 in/sec (13.4 MSCF/D);
Gas Rate Flowing in Dip Tube = 0.61 MSCF/D

Test Point No 6
Separator Vsl=6 inch/sec (276 B/D); Casing Vsg=40.1 in/sec (76.3 MSCF/D);
Gas Rate Flowing in Dip Tube = 0 MSCF/D (not measurable)

Figure 11- View of Gas Bubbles at the Dip Tube Entry for Test Points No. 4 and No. 6 Shown in Figure 7

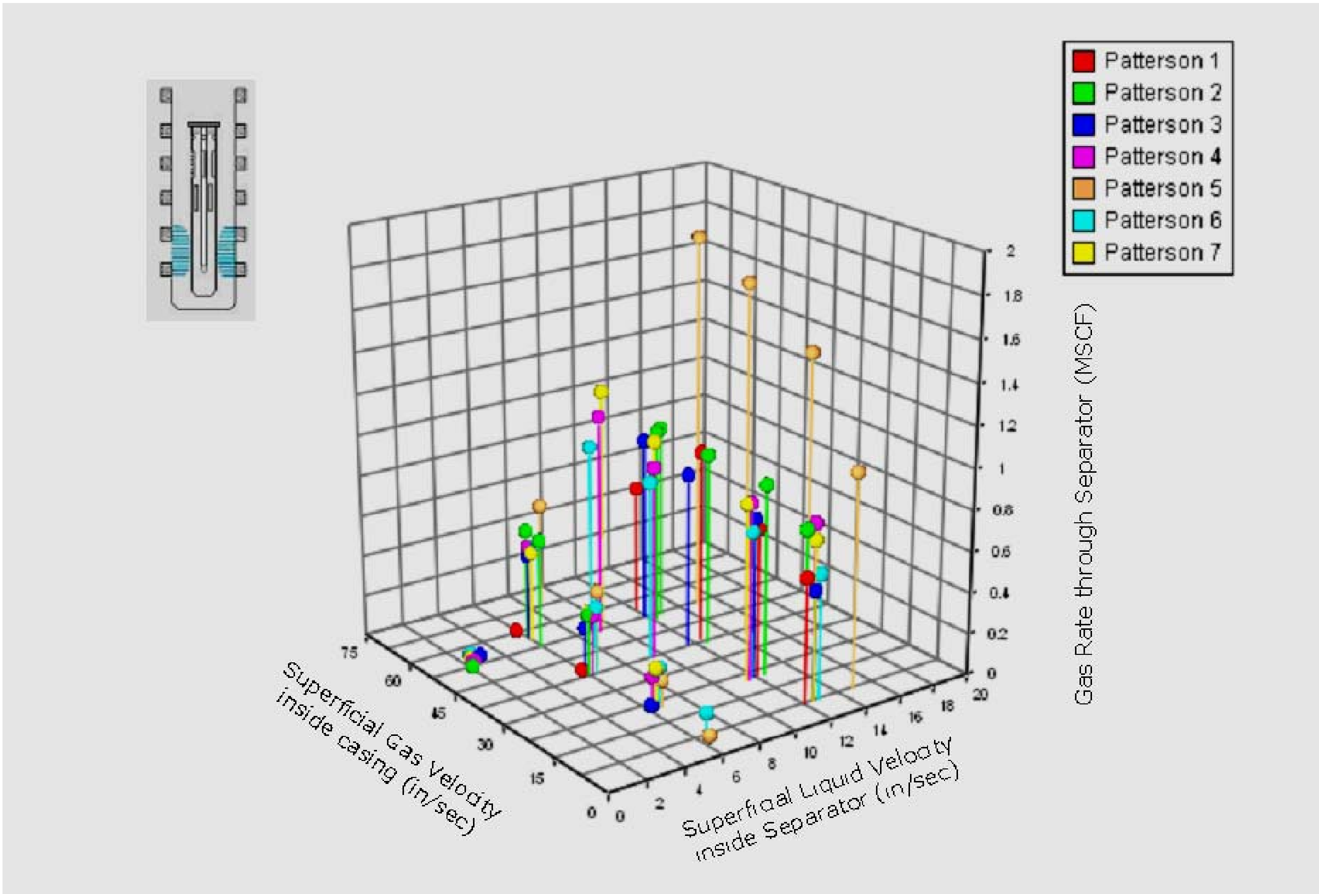


Figure 12 - Comparison, all Patterson Separators at 10 psi with Separator Ports Above the Casing Perforations

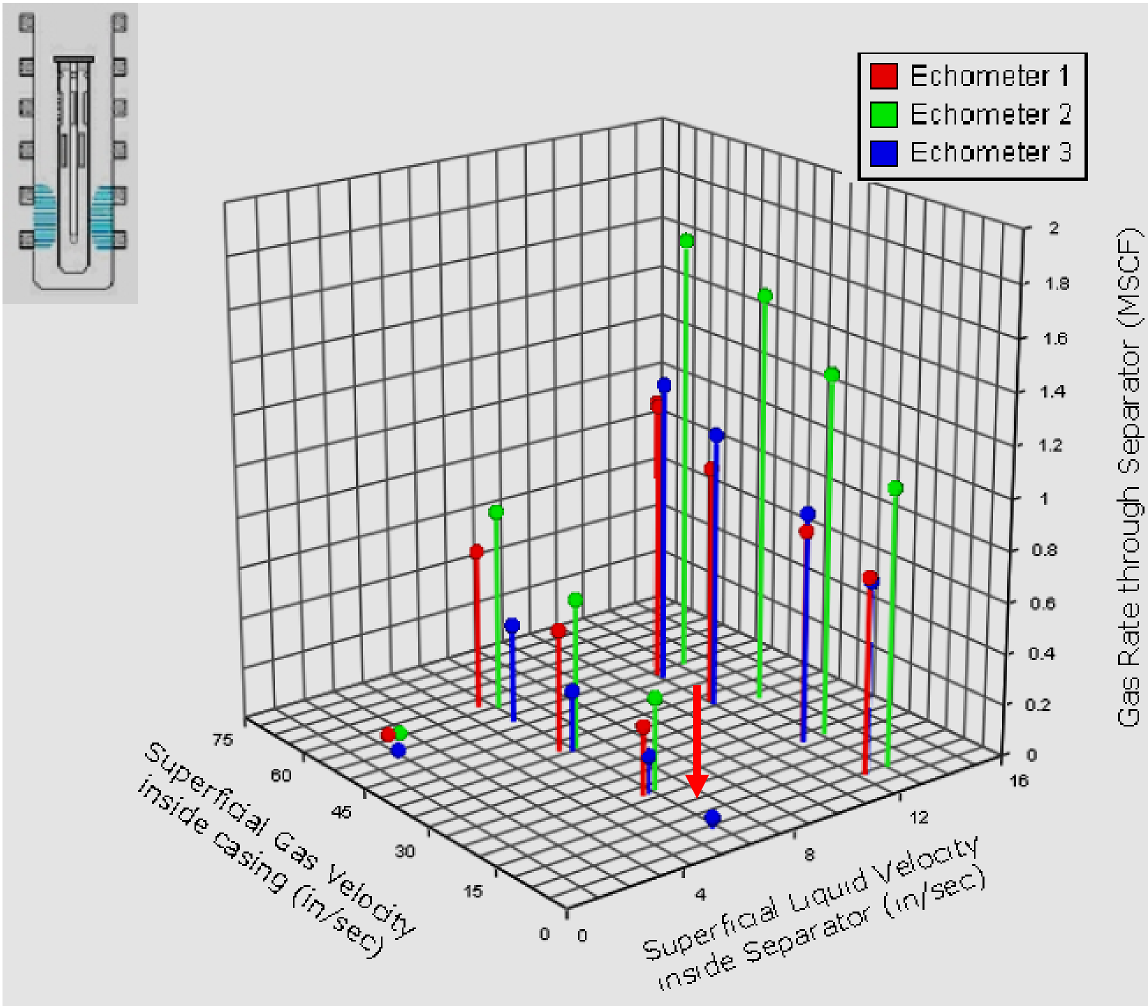


Figure 13 -Comparison of all Echometer Separators at 10 psi with Separator Ports Above the Casing Perforations. The vertical arrow indicates the flow conditions for the field test in the Vogt8 well.

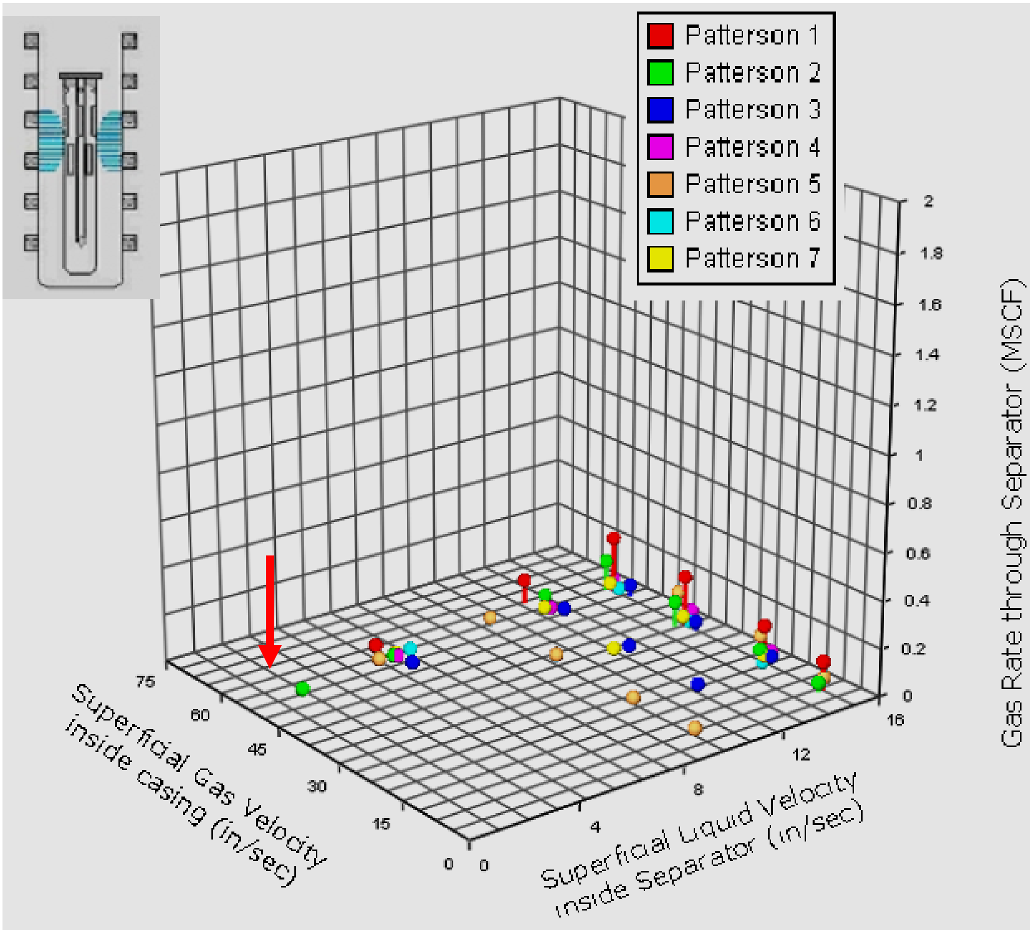


Figure 14 - Comparison all Patterson Separators at 10 psi with Separator Ports Opposite to the Casing Perforations. The vertical down-arrow indicates the flow conditions for the field test on 9/16/2002 in well 24R-24.

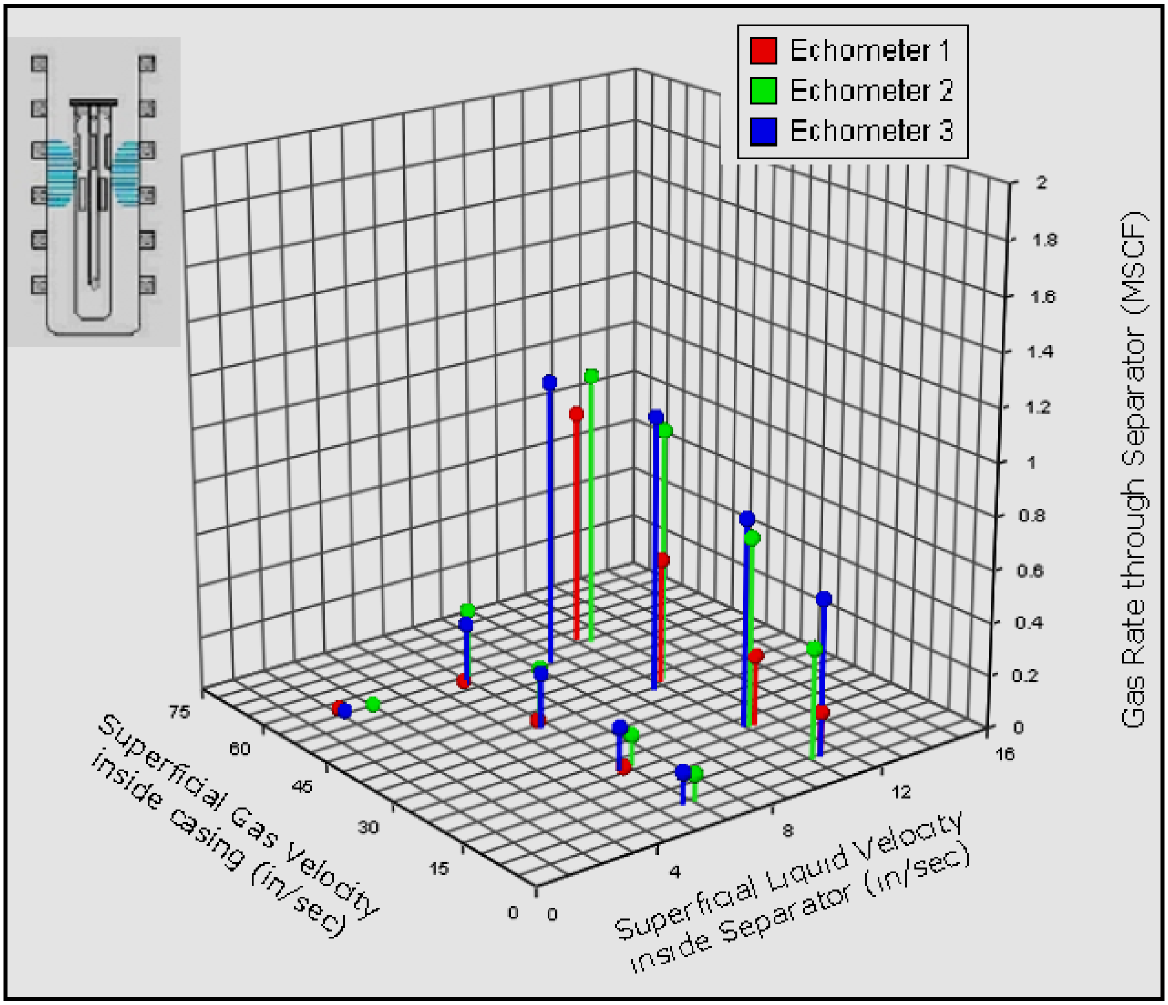


Figure 15 - Comparison all Echometers at 10 psi with the Separator Ports Opposite to the Casing Perforations

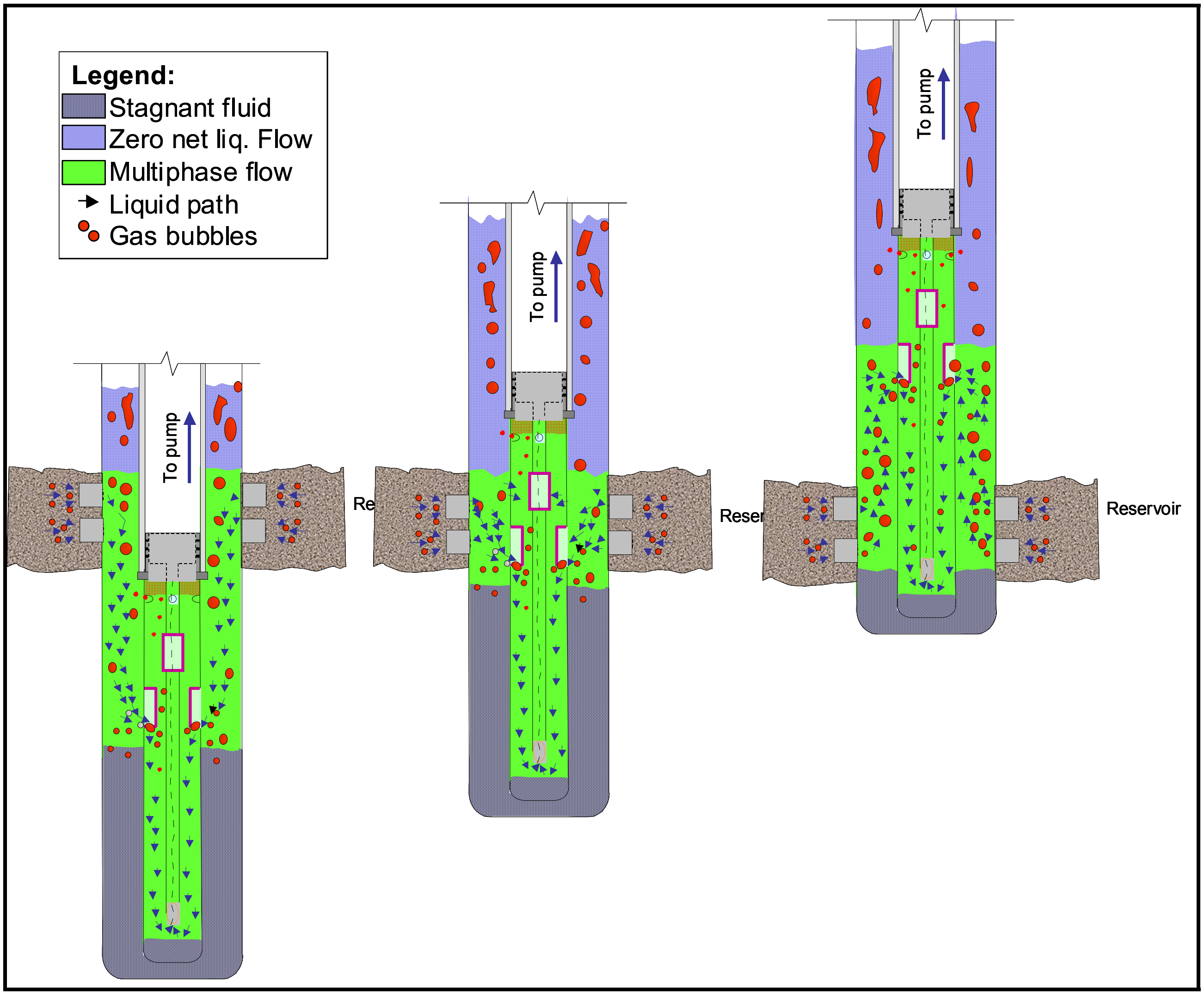
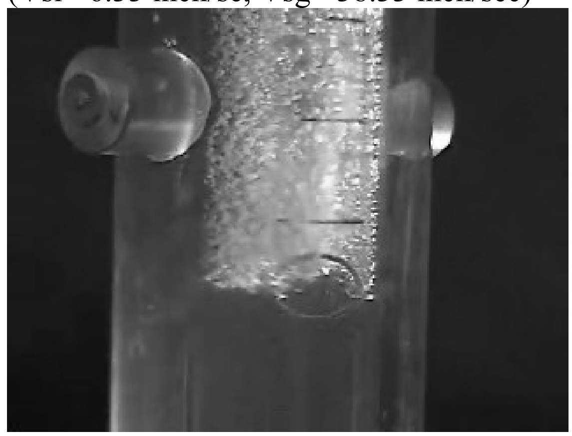


Figure 16- Fluid Flow Paths in Separator

A- Separator Ports Opposite the Casing Perforations

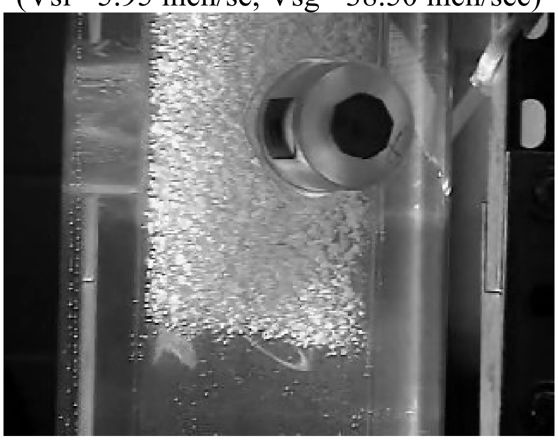
Test 6 –Diameter 1.0 inch
(Vsl= 6.31 inch/se, Vsg= 38.59 inch/sec)

Test 6-Diameter 1.5 inch
(Vsl= 6.33 inch/se, Vsg= 38.33 inch/sec)



B- Separator Ports Above the Casing Perforations

Test 6-Diameter 1.0 inch
(Vsl= 5.95 inch/se, Vsg= 38.50 inch/sec)



Test 6 - Diameter 1.5 inch
(Vsl= 6.49 inch/se, Vsg= 38.00 inch/sec)

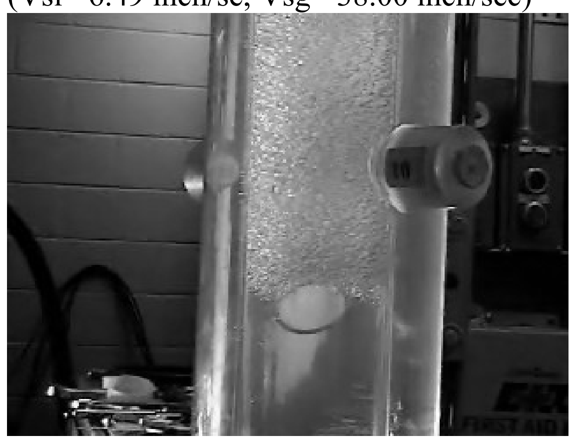
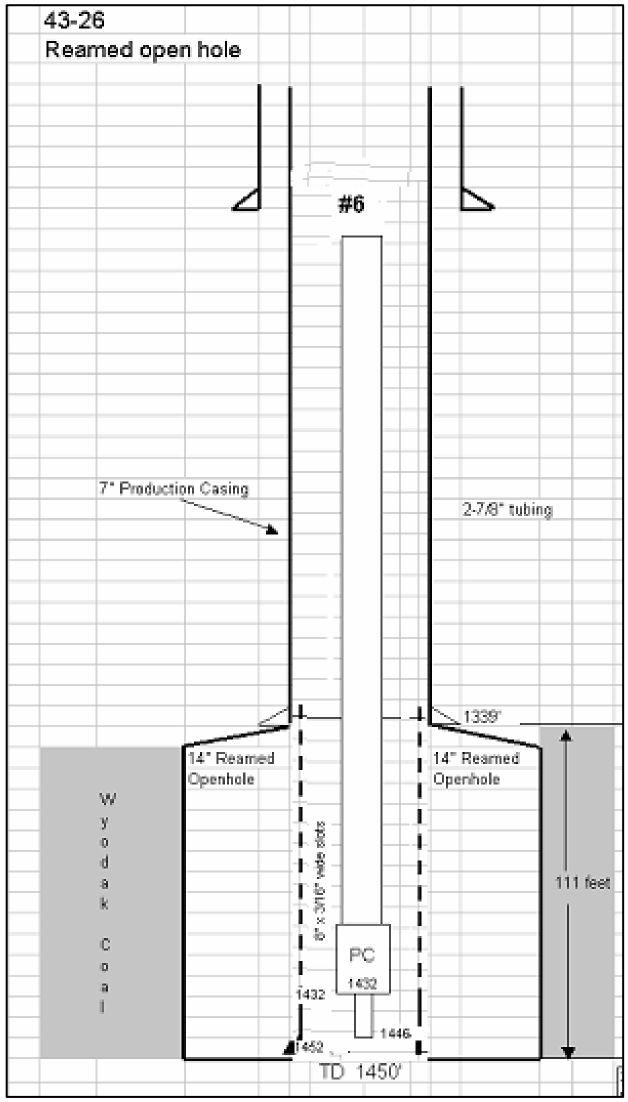


Figure 17 - Effect of the Dip Tube Diameter – Echometer Separators



(A)- Well 43-26 (B) Well 24R-24

Figure 18 –Field Installations of Patterson Type Separators

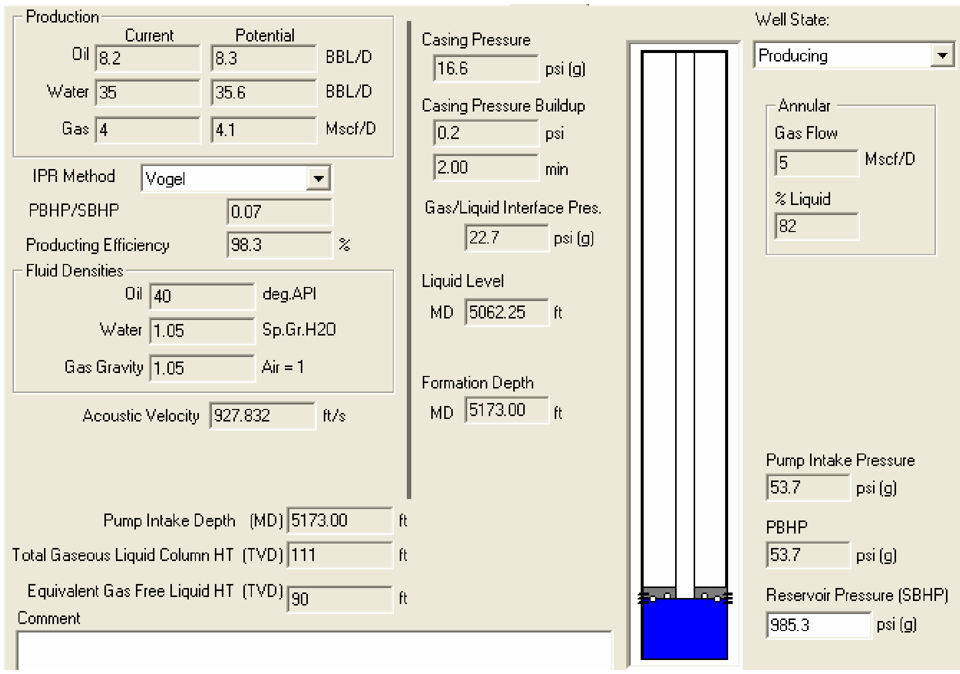


Figure 19 - Liquid Level Test on Vogt 8 With Poor Boy Gas Separator

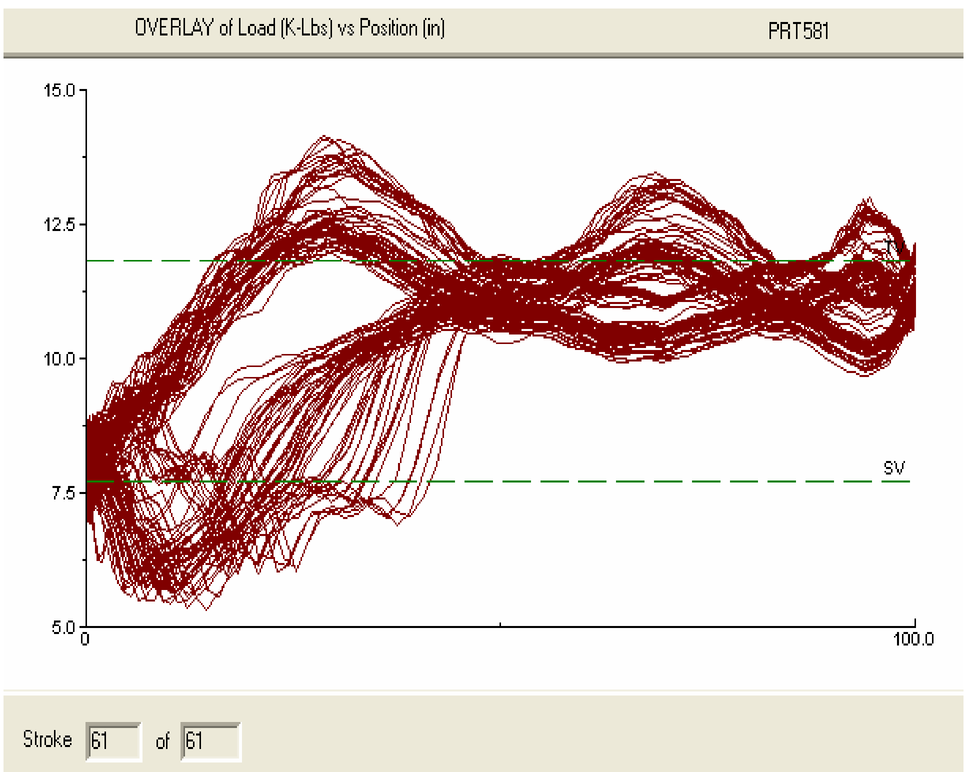


Figure 20 - Dynamometer Cards on Vogt 8 After Well Down 10 Minutes

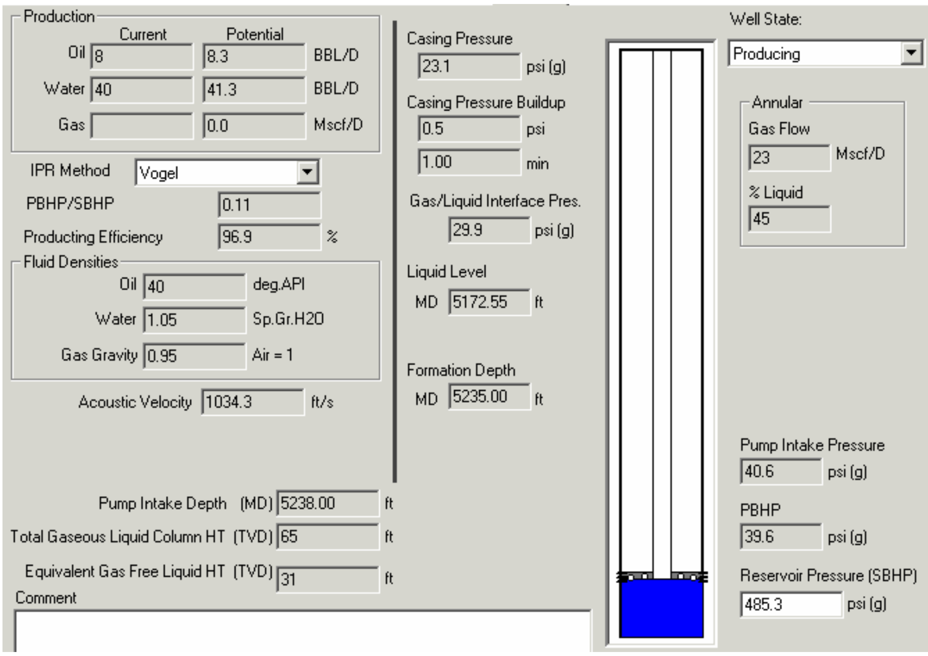


Figure 21 - Liquid Level Test After Echometer Gas Separator Installed

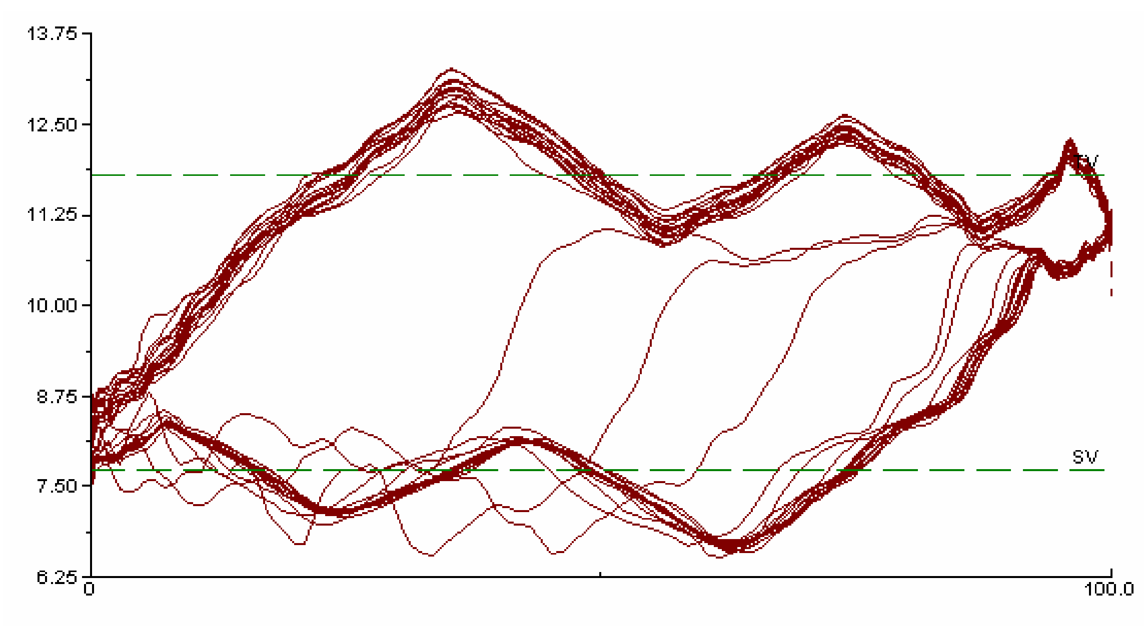


Figure 22 - Dynamometer Cards on Vogt 8 After Well Down 10 Minutes

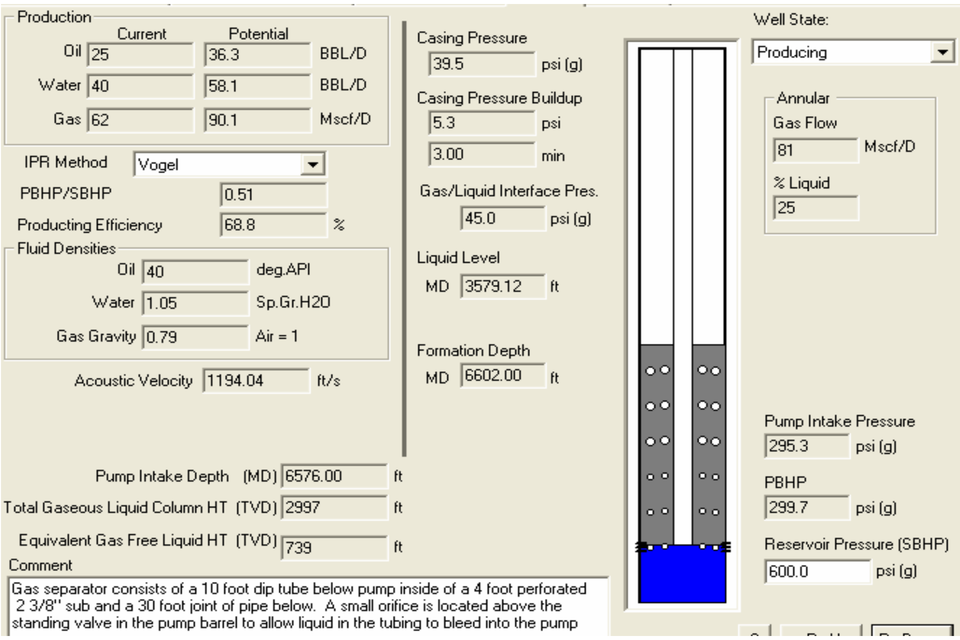


Figure 23 - Jones 1 Initial Fluid Level Test – Poor Boy Separator

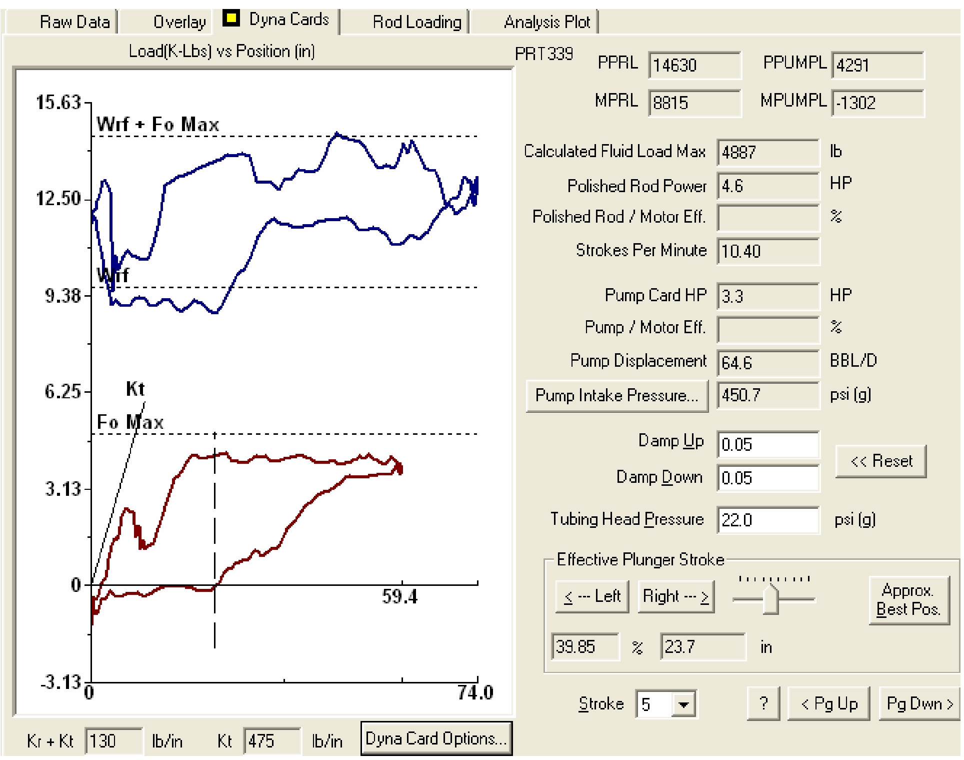


Figure 24 - Jones 1 Initial Dynamometer Test – Poor Boy Separator

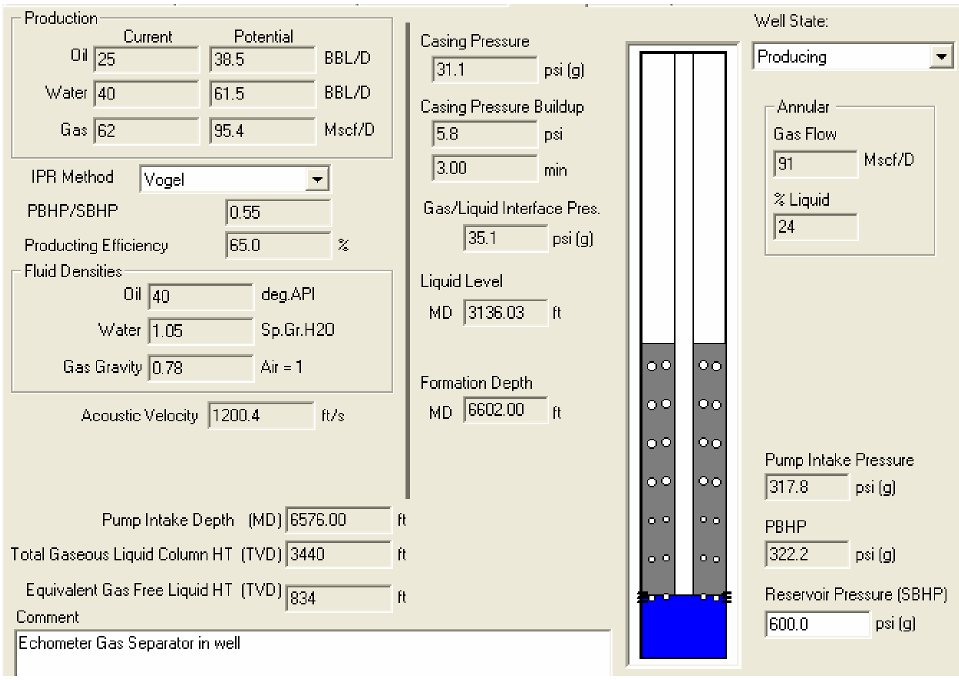


Figure 25 - Liquid Level Test After Echometer Gas Separator Installed in Jones 1

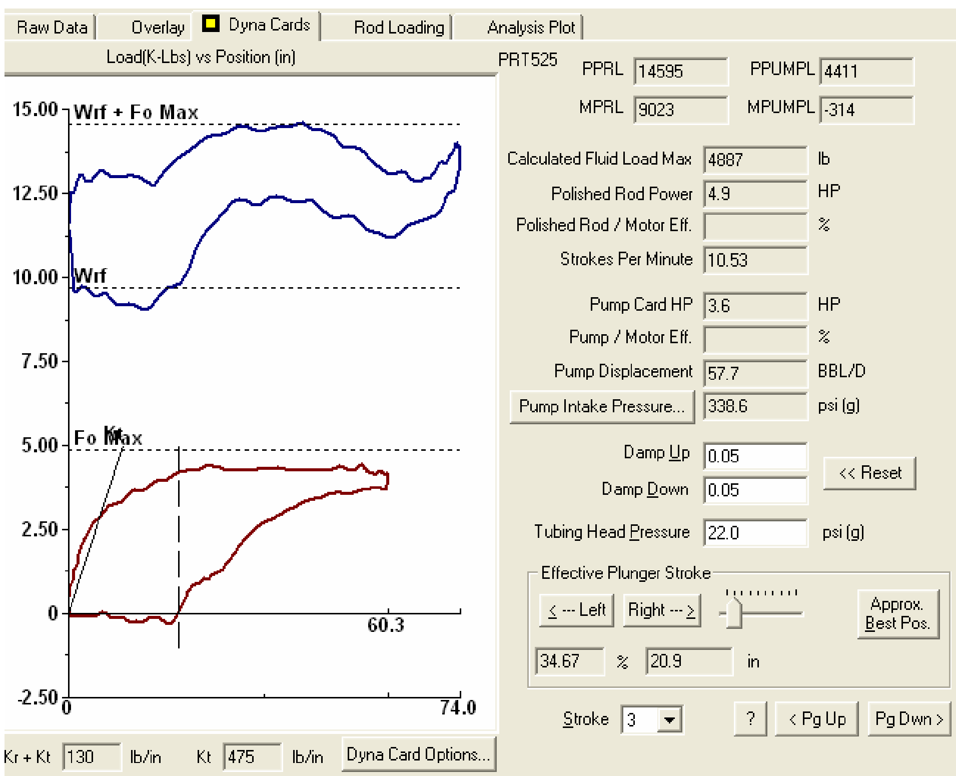


Figure 26 - Dynamometer After Echometer Gas Separator Installed in Jones 1