

DOWNHOLE DIVERTER GAS SEPARATOR

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ABSTRACT

The Downhole Diverter Gas Separator increases the liquid capacity and gas separation capacity over conventional poor boy or Improved Collar Sized downhole gas separators. The increased separation capacity of the diverter gas separator is provided by using the larger tubing-casing annulus for both gas separation and liquid separation. A simple movable rubber seal is used to divert the flow of liquids and gas vertically from below the rubber seal through a central tube approximately 5 feet in length. When the fluids exhaust into the tubing-casing annulus above the seal, the large annulus flow area reduces the annular gas velocity which allows the liquid to fall back through the large area tubing-casing annulus into the pump intake. Larger tubing-casing annular area below the diverter exhaust port provides high liquid capacity. Large tubing-casing annular area above the diverter exhaust port reduces the gas velocity, reduces liquid holdup and provides high gas separation capacity.

INTRODUCTION

A large majority of pumping wells are producing from reservoirs in which the pressure has declined below the bubble point pressure of the hydrocarbon fluid mixture in place, so that a significant permeability to the gas phase is present throughout the reservoir. Both gas and liquid will flow from the drainage radius to the wellbore. Even if the pressure away from the wellbore is above the bubble point pressure, the additional pressure drawdown that is established by using a pumping system causes a further reduction of pressure in the vicinity of the wellbore, so that in most cases the fluid flowing through the perforations consists of a mixture of liquid and gas. The recent advent of numerous horizontal wells that initially produce naturally but in a relatively short time require artificial lift to maintain an economically justifiable flow rate has brought to the forefront the need to also address downhole gas separation in high flow rate wells. Since the pump intake is either located above the perforations or above the horizontal section, a two-phase mixture will always be present at the pump intake and cause a reduction of the volumetric efficiency of the pump. A portion of the gas will percolate up the annulus to the surface and a portion of the gas will be admitted into the pump. The fraction of gas admitted into the pump depends on many physical quantities, such as the velocity of the gas and liquids in the annulus, the location of the pump intake with respect to the wellbore axis, the inclination of the wellbore, the pumping rate, the fluid properties, and other parameters. The volumes of liquid and gas entering the pump will be in a ratio that approximately reflects the in situ gas-liquid ratio at the pump intake. The pressure of this mixture of gas and liquid will be very close to the pressure that exists in the annulus at the depth of the pump intake. The greater the volume of gas in the pump, the greater the compressibility of the fluid that the pump has to handle. This results in a great loss of volumetric efficiency, lower liquid capacity and premature failure of the pump.

DOWNHOLE GAS SEPARATORS

Effectively separating free gas from liquid at the base of the well optimizes the performance of any pumping system and ultimately prolongs pump life. Effective free-gas separation ensures that mostly liquid enters the pump and that the majority of the produced gas flows up through the casing-tubing annulus. The majority of published studies¹⁻²¹ of downhole gas separators agree that:

The most effective gas separator is the casing annulus (natural gravity separation), since its large diameter provides the largest annulus area for gas-liquid gravity separation to occur.

When the pump intake is set below the perforations and there is adequate flow area, gas can be produced through the casing-tubing annulus, and almost none of the gas will enter the pump as long as the liquid velocity does not exceed the slip velocity of the gas bubbles present in the annular volume between the perforations and the pump intake. When the pump intake cannot be set below the perforations due to operating constraints or in the case of horizontal wells where the pump generally is set shallower than the horizontal section, a downhole gas separator (also known as a gas anchor) should be installed ahead of the pump in order to eliminate the majority of the gas in the fluid before it reaches the intake. The disadvantage of these types of separators is that they can handle a smaller gas and

liquid rate since they have to fit inside the wellbore and consequently their dimensions and corresponding flow areas have to be smaller than those provided by the full casing annulus.

Basic Mechanics of Downhole Gas Separation

The two main parameters that control the efficiency of a downhole separator are as follows:

- gas bubble slip velocity
- liquid downward velocity

Figure 1 is a schematic of a gravity-driven static downhole gas separator installed below a downhole plunger pump. Free gas enters with the liquid through either casing perforations or an open-hole formation located some distance below the pump or a horizontal wellbore section completed with a pre-perforated liner or screen. As the two-phase mixture reaches the separator, it is hoped that the majority of the gas in the annular space flows past the separator, into the upper part of the well through the gaseous liquid column, and eventually reaches the top of the well and flows into the surface flow line. The liquid that enters the separator will drag a certain volume of gas bubbles to the pump intake depending on the liquid rate required by the pump.

The less-dense phase in the mixture (the gas) has an upward velocity relative to the denser phase (the liquid). Each gas bubble in the separator annulus (the annular area between the mud anchor and the dip tube) has an upward velocity relative to the liquid, known as the *slip velocity* that is related to the bubble diameter and the liquid properties. Depending on the liquid downward velocity and the individual gas bubble's slip velocity, some of the smaller gas bubbles inside the separator are transported by the liquid into the dip tube while other larger gas bubbles can flow upward and out through the separator vent ports that ultimately vent out through the casing-tubing annulus. When the liquid velocity exceeds the slip velocity of a gas bubble of a given size, the gas bubble will be entrained downward to the dip tube entrance and into the pump. For a given gas flow rate, the capacity of a downhole gas separator is defined as the maximum liquid rate that can flow through the separator without entraining a significant volume of gas into the pump intake.

GAS BUBBLE SLIP VELOCITY

A gas bubble submerged in a moving liquid is subjected to the action of viscous drag and a force due to buoyancy. When the liquid is stationary, the gas bubble is subjected only to gravity and buoyancy, which results in an upward velocity defined as the *gas bubble slip velocity*. Both Stokes Law and experimental observation indicates that the slip velocity decreases as the bubble diameter decreases and as the viscosity of the liquid increases. Figure 2 shows results of laboratory measurements²⁰ of gas bubble slip velocity as a function of bubble size and liquid viscosity. Measurements were made by video observation of individual air bubbles rising in an annular geometry similar to that of a downhole gas separator, except with a stationary liquid³. Different liquids were used to cover the range of viscosity from 1 to 3,500 cp. Discrete sets of bubble sizes from 1/4 to 1 1/4 inches were selected to obtain experimental averages of their corresponding slip velocities.

The data trends indicate that there is relatively small influence (about 20% variation) of viscosity on slip velocity for the range between 1 and 100 cp for bubbles from 1/4 inch to 3 inches diameter. This range of viscosity covers a large number of oil well pumping operations (excluding heavy oil). If the diameter of the smallest bubble to be separated from the liquid is 1/4 inch, then a slip velocity of about six inches/sec can be used as the characteristic slip velocity in order to determine the liquid capacity of a gravity separator of a given geometry. This slip velocity has been used historically for the design of downhole gas separators and results in the following rule of thumb:

A flow rate of 50 bpd through a cross section of 1 square inch results in a liquid velocity of 6 inches/sec. If that flow rate is not exceeded within the separator, a minimal amount of gas will flow into the pump. If that flow rate is exceeded, then the gas flow into the pump will increase proportionately to the flow rate above the guideline limit. Figure 3 illustrates these concepts using photographs of the observed flow near the entrance to the dip tube for three different liquid flow rates.

At 243 bpd, the liquid velocity is 5 inches/sec, and only very small bubbles are visible inside the separator and moving towards the dip tube inlet. At 275 bpd, the liquid velocity increases to 6 inches/sec. A swarm of 1/4-inch gas bubbles has formed in the annular space between the dip tube and the separator inner wall. These bubbles are in equilibrium with the downward moving liquid and do not enter into the dip tube. The liquid is flowing through the suspended bubbles and only smaller diameter gas bubbles enter the tube. At 420 bpd, the liquid velocity has



increased to 9 inches/sec, and gas bubbles that are about 1/4 inch and smaller move continually downward in the separator annulus, into the dip tube, and to the pump intake. The gas-liquid mixture flowing into the pump at this rate has a gas fraction of approximately 45%.

Based on the previous discussion, in order to achieve adequate separation of gas and liquid at the desired liquid production rate, it is necessary to direct the liquid flow downward at the smallest possible velocity by maximizing the flow area.

NATURAL GAS SEPARATOR

In a well, the largest available flow area is the cross section of the wellbore. Thus, using the wellbore as the separator will yield the maximum liquid capacity when the pump intake is set below the bottommost perforations as shown in Figure 4.

When the liquid velocity in the annulus exceeds the limit (six inches/sec), the gas bubbles will eventually be dragged to the pump intake regardless of the distance from the bottom of the perforations. The following table lists the most common combinations of casing and tubing sizes used for constructing downhole gas separators, as well as the corresponding flow areas and liquid capacities.

Field application of this type of natural separator is often subject to a misconception derived from erroneous application of criteria for the design of separators used in surface facilities:

“The distance from the bottom of the perforations or zone, to the intake of the pump or the perforated nipple must be several tubing joints long in order to provide adequate volume for a quieting zone.”

The concept of a “quieting zone” is correctly used for design of surface separators as a means of selecting the internal diameter of the separation vessel based on the retention time required for small gas bubbles, which are dispersed in the liquid, to rise a few inches to the gas/liquid interface when the downward liquid velocity is practically zero. This concept of quieting chamber is totally useless in designing a downhole gas separator where the wellbore diameter is fixed (4-1/2 to 7 inches in most cases) and the separation mechanism is controlled by the viscous drag on the gas bubbles by the significant liquid downward velocity. Increasing the length of the downhole separator to increase the volume of the “quieting chamber” is pointless when the liquid downward velocity exceeds the gas bubble slip velocity. Based on the previous discussion of slip velocity, the gas bubbles (of average diameter equal to or less than 1/4 inch) will eventually reach the pump intake (entrance to the dip tube) whether the distance is a few feet or 30 feet or 60 feet or more if the liquid is moving down at a velocity exceeding 6 inches per second..

Results of laboratory testing using 6-inch-diameter casing and 3-inch tubing for the gas separator show that, once the gas anchor entry ports are located a few feet below the turbulence caused by gas and liquid flow through the casing perforations, virtually no gas bubbles reach the pump when the annular liquid velocity is less than 6 inches/sec.

PACKER SEPARATOR

This type of separator was developed to try to obtain a separation capacity similar to that of a natural gas separator even though the intake of the pump is located above the perforations or the fluid entry depth. As shown in Figure 5, the sealing packer forces all the produced fluids (oil, water, and gas) to flow up inside the small-diameter vertical riser (typically 1 1/2 inches in diameter and 30 feet long) and out into the casing-tubing annulus above the packer. The liquids fall downward while the gas continues up to the surface, where it is produced at the casing head. The liquid intake is at the bottom through a special ported nipple through which flows mostly liquid to the pump.

The performance of this separator is expected to be similar to the performance of the natural gas separator. Liquid capacity is reduced to the extent that the casing-tubing annular cross-sectional area is reduced by the area of the riser pipe (1.76 square inches for pipe with a 1 1/2-inch OD), which would correspond to a reduction in liquid capacity of about 88 bpd for each configuration listed in Table 1.

To overcome this capacity reduction, several alternative designs^{22,23} use a concentric arrangement with a 1-inch tube connecting the bottom entry port to the pump intake that is located about 30 feet above the packer, instead of using the external riser tube. The produced fluids flow to the top of the assembly through the annulus formed by the 1-inch tube and the outer shell of the separator and then exit the tubing-casing annulus through several perforations.

Liquid then falls to the bottom, and gas flows to surface and is vented at the casing head. The liquid then has to rise about 30 feet to reach the pump intake that is set in a landing nipple at the top of the separator assembly.

The existing designs of packer separators also suffer from several misconceptions that cause poor pump fillage and also create operational and installation difficulties as listed below:

1st- The separator length should be at least 25 to 30 ft in length to provide adequate volume for a “quieting chamber”, which is irrelevant as discussed earlier.

2nd- A mechanical packer assembly is required to resist the forces created by the flowing pressure and to prevent leakage of gas from the wellbore below into the liquid “quieting chamber” above the sealing element.

The mechanical packer assembly can be the source of severe installation and retrieval problems, especially in the presence of solids, scale and corrosion. In addition the axial load that is required for packer compression and slip setting forces the use of thick wall piping which reduces all the flow areas in the interior of the separator. This in turn restricts the flow rate that can reach the pump intake given a certain pressure and creates large pressure drops.

As discussed in the next section, an analysis of the flow mechanism shows that the pressure difference across the packer is always minimal and thus it is not necessary to include mechanical slips or other means to support it. This is further substantiated by experimental measurements undertaken using a full scale model of the wellbore and separator operating over a broad range of gas and liquid flow rates.

DOWNHOLE DIVERTER GAS SEPARATOR

This separator design was developed with the objective of achieving the same efficiency and flow rate capacity that could be obtained if it were possible to locate the pump intake below the entry point of free gas into the wellbore. The separator described in this paper is designed to be used in wells where it is not possible to locate the pump intake below the producing interval. The overall performance of this separator is similar to that of a Natural Separator.

The new separator overcomes the disadvantages inherent in the packer type separator depicted in Figure 5, by maintaining the full area of the casing annulus through elimination of the external riser pipe routing the fluid flow within the tool and also by eliminating the mechanical elements of the hook wall packer to facilitate the installation and removal of the assembly even in the presence of solids, scale or corrosion products.

Figure 6 shows a schematic diagram of the Diverter Separator and pictures of some of its principal components.

The diverter separator comprises an outer tube which has a side wall and an interior chamber. The outer tube is open at both ends. An inner tube is located in the interior of the outer vessel and extends from the bottom of the outer tube to the top of the outer tube. At the bottom, the annular area between the outer tube and the inner tube is sealed. The annular area between the wellbore (casing) and the outer tube is closed by means of a set of elastomer cups that separate the upper part of the annulus from the lower part of the well. This arrangement forces all the fluids flowing from the reservoir to enter the separator and flow up the interior tube at which top end is located a discharge port connected to the annular space between the separator outer body and the wellbore. The denser liquid after exiting horizontally through the discharge port falls downwards, under the action of gravity, and accumulates in the annulus above the elastomer cups. The lighter gas flows upwards in the tubing-casing annulus to the top of the wellbore where it flows to the surface production facilities. The liquid that accumulates immediately above the elastomer cups flows through several large ports into the space between the outer and inner tubes of the separator. This annular space is connected at the top of the separator to the seating nipple of the pump so that the liquid can freely flow into the pump as the pump draws in fluid and then discharges the liquid at the bottom of the tubing string. The distance from the bottom of the separator to the pump landing nipple is of the order of 5 to 6 ft. This short distance and the large flow areas are instrumental in keeping the pressure drop, between the separator entry and its discharge into the pump, to a few psi even at the maximum operating flow rates. It is important to note that if the separator were 30 or more feet in length, the combined friction and hydrostatic pressure drop could be of the order of 15 to 20 psi causing the evolution of significant solution gas and a corresponding reduction in pump liquid fillage of up to 30%. The downward flow of liquid from the discharge port to the outlet ports is interrupted by the diverter cups that are installed on a mandrel connected to a retaining ring. The cups' outside diameter is designed to fit closely the inside diameter of the specific casing in the well and prevent the liquid from falling to the lower part of the wellbore.

Diverter Separator Performance

Laboratory testing has been completed to define the range of operating conditions where the separator delivers mostly liquid (95 to 99 %) to the pump under steady state flow conditions. At these gas and liquid rates the volume between the fluid discharge port and the liquid inlet to the pump is occupied by liquid (with only microscopic gas bubbles dispersed uniformly in the liquid) while the space above the fluid discharge port is a short (2-3 ft) column of gas and liquid with the gas percolating freely through the liquid and rising to the top of the annular space. The combined gas and liquid rate that results in this fluid distribution is defined as the separator gas capacity for the particular liquid rate. Liquid (water) rates from 125 to 700 Bbl/day and gas rates from 20 to 80 MSCF/D were injected into a 5 inch OD x 4.7 inch ID casing where a full size diverter separator was installed. Flow tests were conducted at gas/liquid combinations that resulted in the flow pattern and liquid distribution defined earlier. Annular gas flow rates and pressures were recorded for each test.

The following Figure 7 shows typical results from one series of tests with the gas rate plotted as a function of the liquid flow rate.

By repeating tests at additional flow conditions and pressures a generalized performance relation has been established and has been incorporated into a spreadsheet calculator²⁴ that allows the user to determine the limiting gas flow rate that a diverter separator can handle at maximum efficiency, given the wellbore dimensions, the desired liquid rate and the operating pump intake pressure and temperature.

Throughout the laboratory testing it has been observed that the pressure drop across the diverter is minimal (of the order of 1-4 psi) and generally the pressure above the diverter exceeds the pressure below. This proves that it is not necessary to have an expandable packer to isolate the annulus and divert the liquid flow downwards into the separator inlet to the pump. Since the overall length of the separator is only 5-6 feet the pressure drop from the inlet to the pump intake (standing valve) is only from 2-3 psi depending on the density of the liquid. Figure 8 shows the pressure distribution that would be observed in a field installation where the annular pressure above the separator is 58 psi (generated by a casing head pressure of about 50 psi)

This example clearly shows that there always is minimal pressure difference across the diverter cups and therefore it is totally unnecessary to use a compression packer which is designed to support differential pressures of several thousand psi.

OPERATIONAL FEATURES

The absence of the mechanical packer slips facilitates running the tool with minimal problems. The diverter cups are elastic, manufactured of high quality elastomers that are matched to the environmental conditions of the wellbore.

INSTALLATION

Separator installation needs to accommodate some tubing movement without excessive wear of the diverter cups. This is accomplished by allowing some free motion of the diverter cups relative to the mounting mandrel as the tubing stretches and contracts during a pump stroke in the event the tubing is not anchored or if it is anchored several tubing joints above the pump landing nipple. Normally the separator is run with the tubing anchor one joint above. The length of the mounting mandrel can be selected by the operator in accordance with the estimated tubing stretch for a given installation (depending on presence or absence of tubing anchor and actual location of the anchor when present) and operating conditions.

RETRIEVAL

In addition to the fluids (oil, water and gas), some wells may produce sand or fine solid particles (coal fines) that may accumulate above the diverter cups and obstruct the flow of liquid through the liquid inlet ports and in addition may cause the separator assembly to become stuck inside the casing making it difficult to retrieve the tubing and the separator assembly when repairs are required. To solve this problem a set of shear pins is located at the bottom of the separator below the diverter cups. The pins hold in place a retainer ring that prevents the diverter cups from sliding off the bottom tube of the separator. The shear pins are designed to fail at a specified axial pull (typically 3000 to 4000 lbs) and allow the separation of the body of the separator from the diverter cup assembly. This allows retrieval of the tubing and the separator, while the diverter cups are left in the wellbore for subsequent disposal (displacement to the bottom of the well or retrieval with specialized fishing tools)

MONITORING OF SOLIDS ACCUMULATION

Accumulation of sand or debris above the diverter cups can be easily detected from surface dynamometer and/or fluid level measurements. Blockage of the flow from the casing annulus into the separator and pump results in starving of the pump and causes incomplete liquid fillage of the pump barrel. This is easily observed from analysis of the dynamometer data and is accompanied by an increase in fluid level in the annulus which is detected from fluid level measurements. The well will require servicing. A relatively simple and inexpensive remedy to the blockage by solids can often be practiced by flushing the separator using the fluid in the tubing above the pump. This requires un-seating the pump from the seating nipple.

When the pump is unseated, liquid in the tubing will flow down the tubing and discharge out of the gas separator through the gas separator liquid inlet ports. The discharging liquid will be at high pressure. This will wash the sand and debris away from above the diverter. The discharging liquid will flow up the casing annulus and carry the sand. Probably ½ of the liquid and sand will also flow down through the gas separator into the lower portion of the casing below the diverter and fall to the bottom of the well. After the pump is re-seated the pumping system is restarted and after some flow stabilization time the dynamometer and fluid level tests are repeated to verify that the well, the separator and the pump are operating normally.

SUMMARY

The diverter downhole separator described in this paper is designed to be used in wells where it is not possible to locate the pump intake below the producing interval. As shown in laboratory testing the overall separation capacity of this separator is equivalent to that of the wellbore when the pump intake is set below the gas entry point, that is, its liquid rate capacity is that of a Natural Separator.

The design of the Diverter Gas Separator has significant advantages over similar types of separators:

- 1- Does not use mechanical slips or expandable packer.
- 2- It is short and has large flow areas so it minimizes pressure drop to the pump intake.
- 3- Enhances gas/liquid separation through horizontal flow impingement on the casing wall.
- 4- Allows back flushing of solids.
- 5- Provides fail-safe release of separator body from elastomer cups via shear pins.

At the time of drafting this paper, Echometer Co. is planning with the assistance of several oilfield operators to undertake field tests of the Diverter Gas Separators in a variety of vertical and directional wells. Results of the tests will be presented at the 2012 SWPSC and an addendum to this paper will be distributed.

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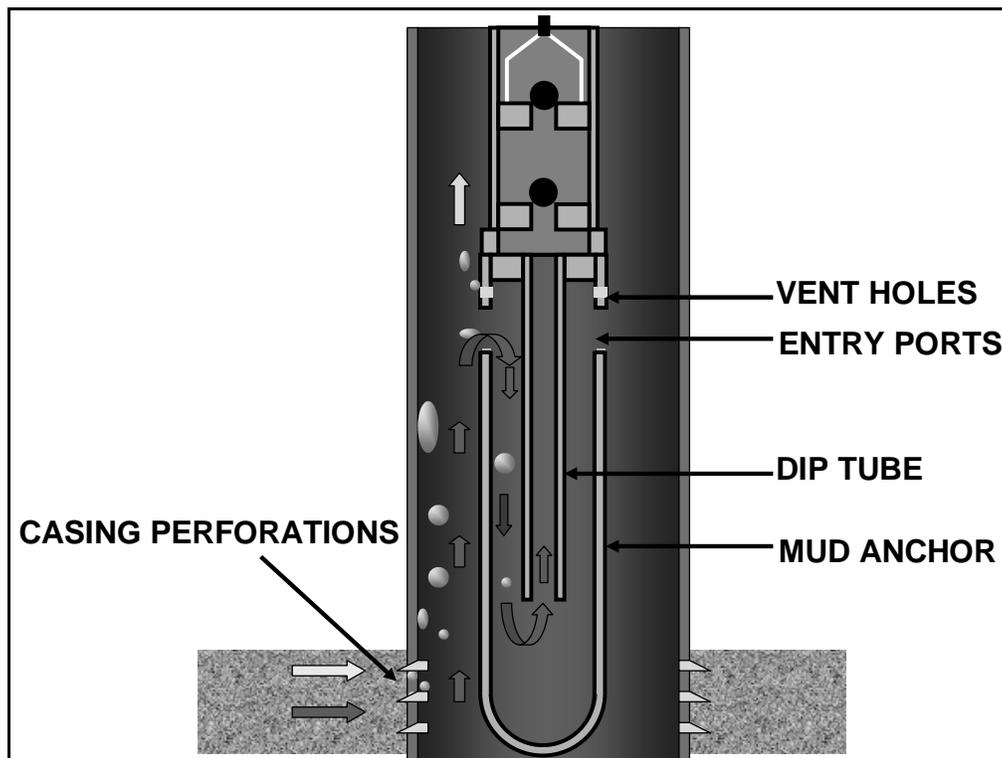


Figure 1 - Downhole Gas-Liquid Separator

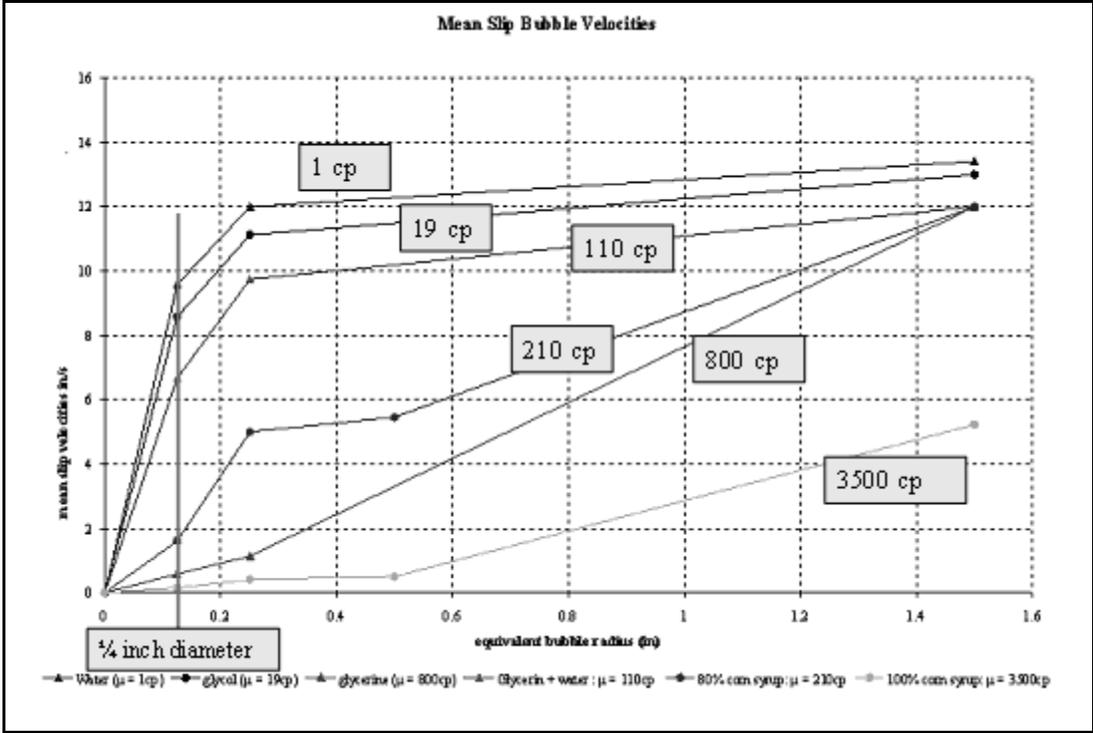


Figure 2 - Air Bubble Slip Velocities in Liquids of Different Viscosity

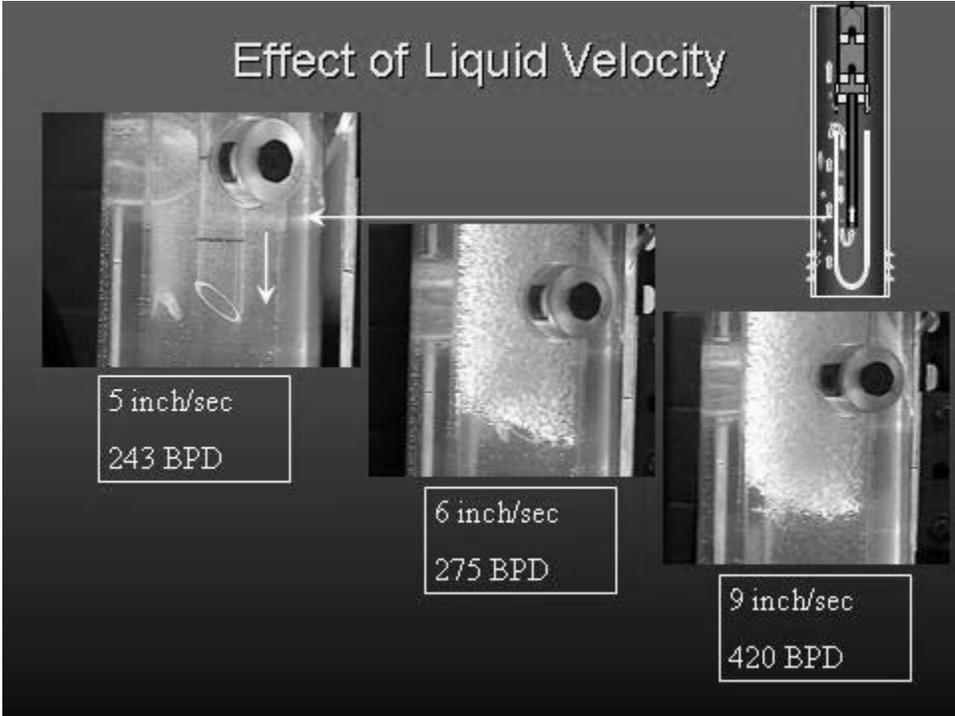


Figure 3 - Gas Entrainment into the Separator Dip Tube at Increasing Rates

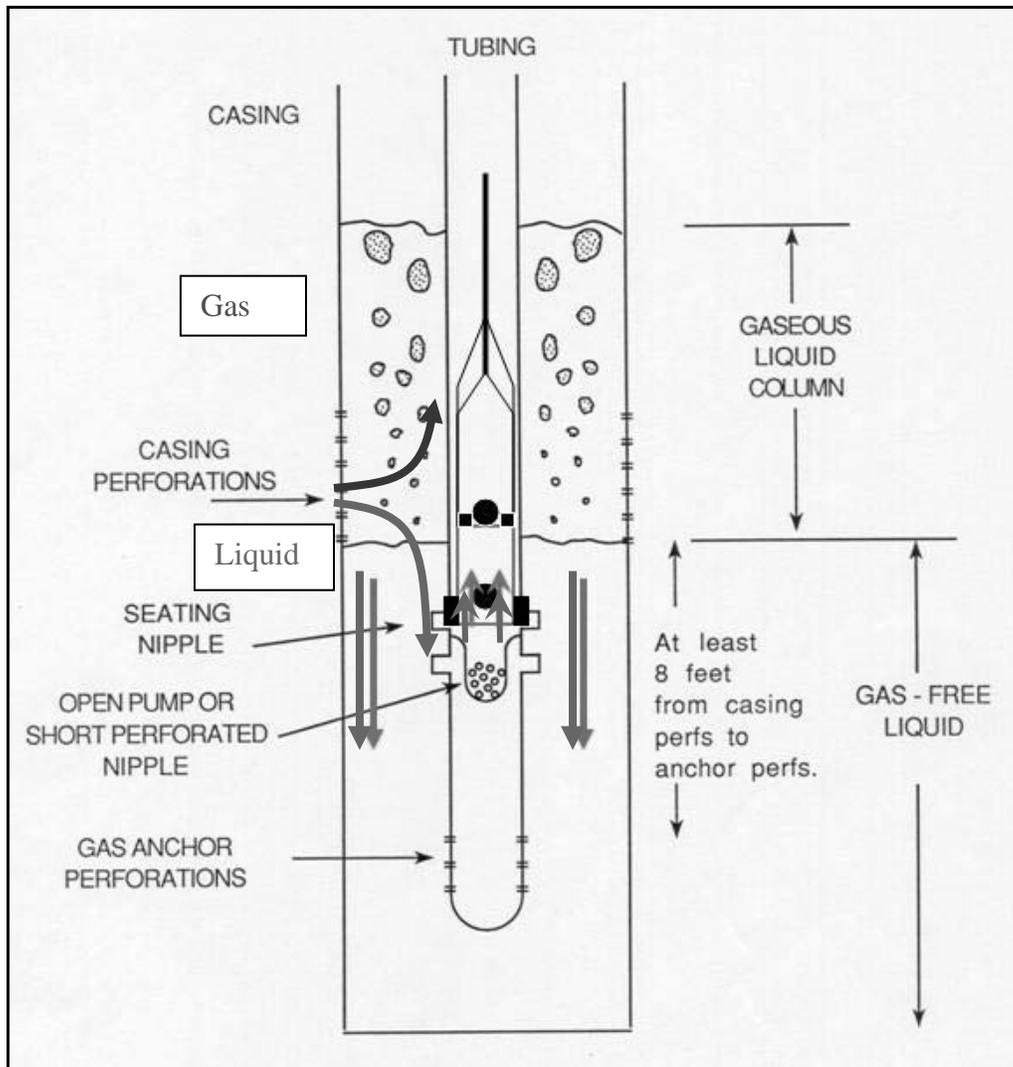


Figure 4 - Natural Gas-Liquid Separator

Table 1
Liquid capacity of natural gas-liquid separators with the pump intake below the fluid entry zone.

	Casing size (inches)	Gas Anchor size (inches)	Description	Annulus area (inches ²)*	Liquid capacity (bpd)
Conventional					
	7	3 1/2	Perforated tubing sub	23.1	1,150
	7	2 7/8	Perforated tubing sub	26.7	1,335
	7	2 3/8	Perforated tubing sub	28.8	1,440
	5 1/2	2 7/8	Perforated tubing sub	12.7	635
	5 1/2	2 3/8	Perforated tubing sub	14.8	740
	4 1/2	2 7/8	Perforated tubing sub	6.1	305
	4 1/2	2 3/8	-	8.2	410
Higher capacity					
	5 1/2	1 1/2	Perforated line pipe	16.4	820
	4 1/2	1 1/4	Perforated line pipe	10.4	520

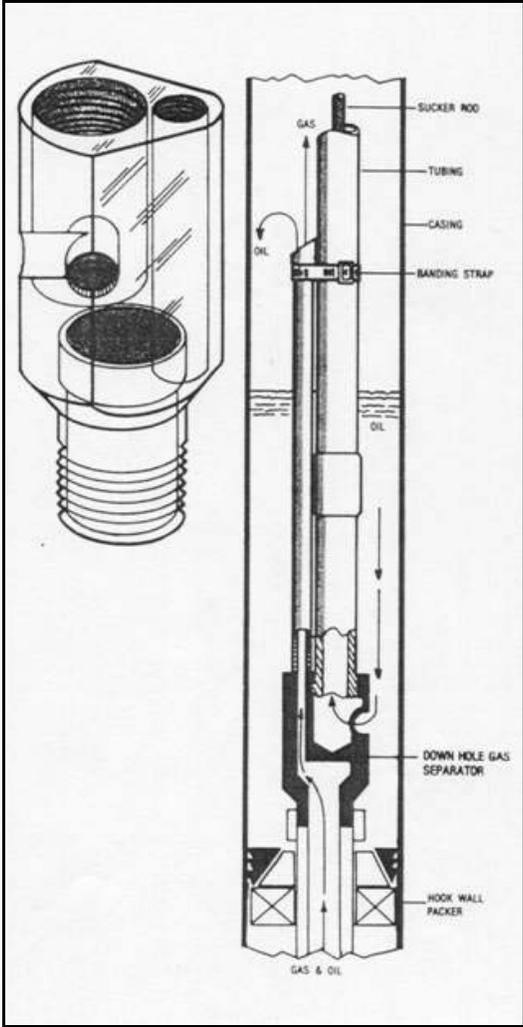


Figure 5 - Packer Style Separator

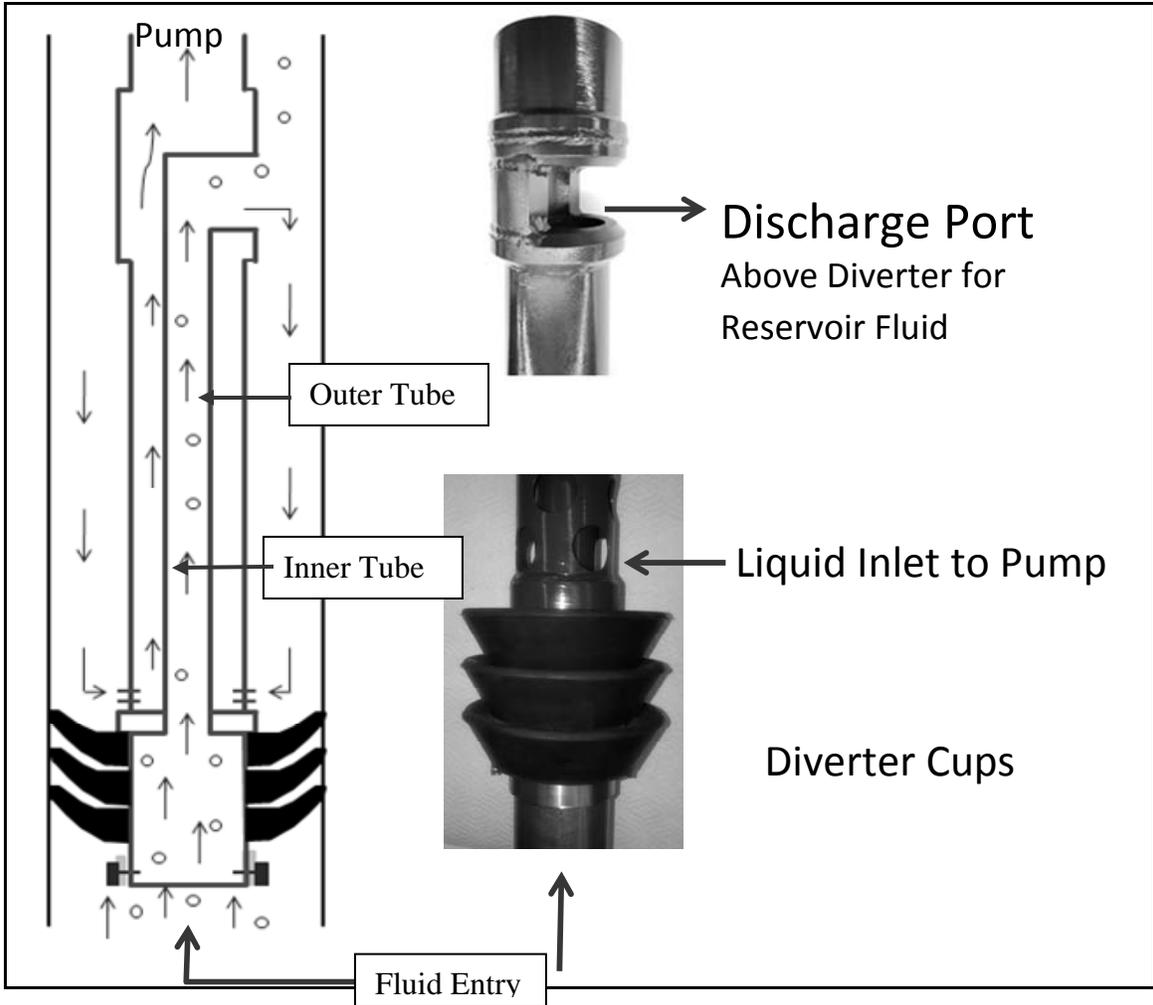


Figure 6 – Diverter Gas Separator

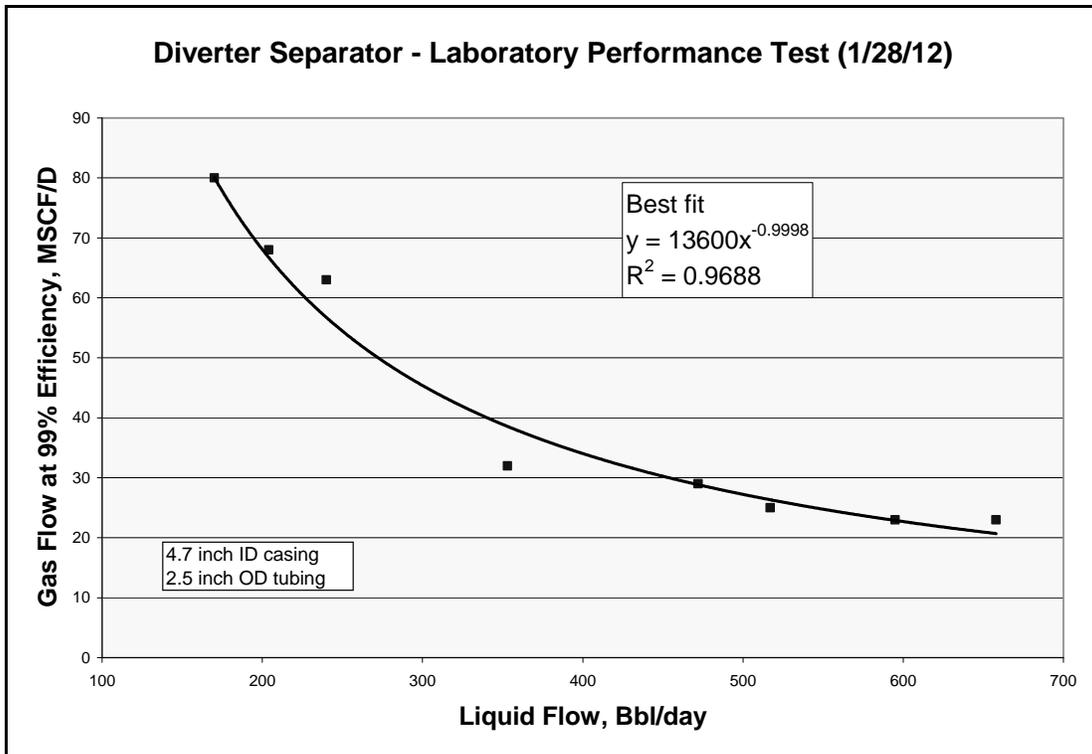


Figure 7 –Typical laboratory test results for 5 inch pipe.

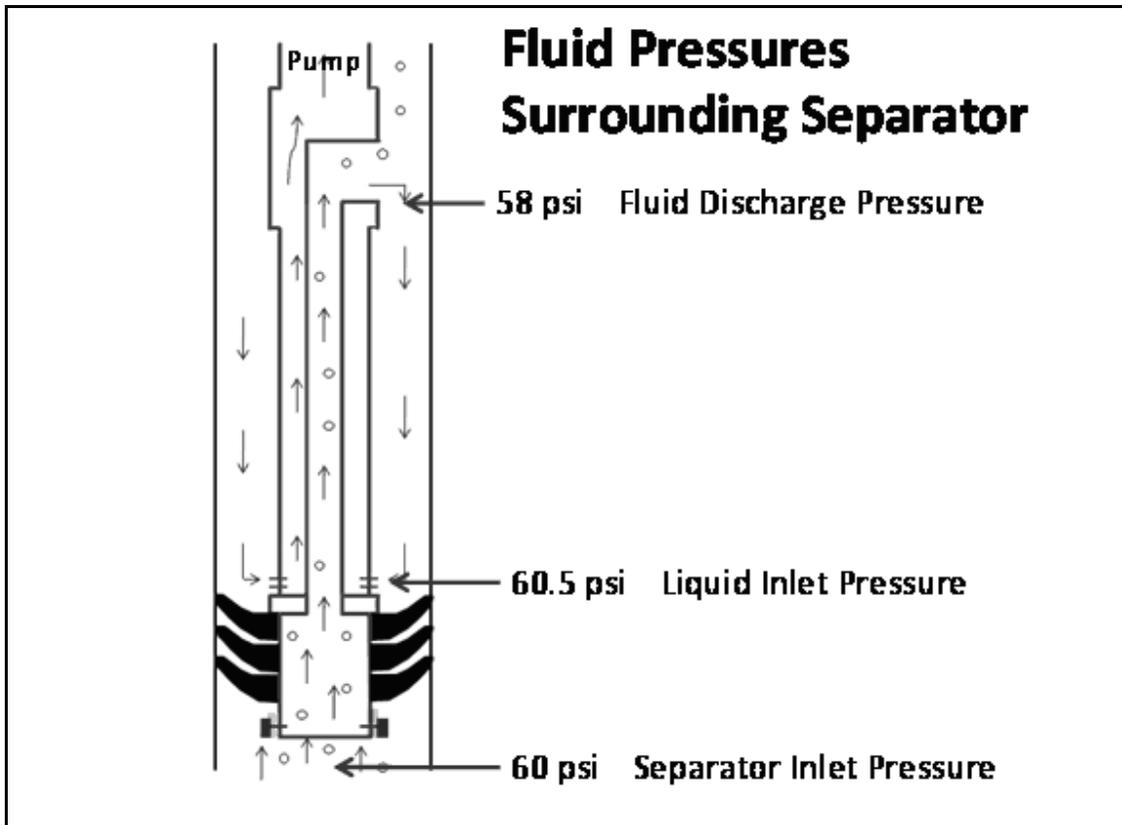


Figure 8 – Estimated pressure distribution for a field installation.