IMPROVED DOWNHOLE GAS SEPARATORS

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INTRODUCTION

Hundreds of wells have been tested using power measurement equipment, dynamometers and acoustic liquid level instruments.[1,6,7] Many of these wells were operating at less than 30% efficiency. Often, the main cause of inefficient operations is an inefficient downhole gas separator. Inefficient gas separators can be identified by obtaining an acoustic liquid level test which indicates a high gaseous liquid column above the pump and the analysis of dynamometer data which indicates incomplete pump fillage. Periodic acoustic liquid level tests and dynamometer measurements should be performed to verify that the downhole gas separator is operating efficiently. Tapping bottom with the pump, rimming the pumping unit at excessive speed, operating the pumping unit for excessive periods of time, increasing the tubing pressure or increasing the casing pressure is not the proper procedure for correcting inefficient downhole gas separation.

To correct inefficient downhole gas separation, the first attempt should be to set the pump below the fluid entry zone if feasible. This is the most efficient method of downhole gas separation. However, if the pump is set above the fluid entry zone, a gas separator should be used below the pump that offers an efficient gas/liquid separation chamber with low dip tube friction loss which results in complete pump fillage if sufficient liquid inflow into the wellbore is available.

In this article, downhole gas separators are divided into two types that are very different. If the gas separator is placed below the fluid entry zone, a single dip tube type of gas separator should be used below the pump seating nipple. If the gas separator is placed in or above the fluid entry zone, a gas separator assembly should be used that consists of an outer barrel having ports at the top of the barrel with a dip tube extending from the pump inlet down into the outer barrel and opening below the ports. An operator should be able to tell whether a gas separator is being used above or below the formation after viewing the gas separator. They should be built differently. In this paper, the outer barrel of the gas separator to be used above the formation is called outer barrel. It is sometimes called a mud anchor. The inner tube is called a dip tube and it is sometimes called a gas anchor. Clegg [2,3,4] discusses many types of gas separators and the principles of gas/liquid separation.

GAS SEPARATOR BELOW THE FORMATION

If the seating nipple is placed at. least 5 feet below the formation, the seating nipple can be at the bottom of the tubing without an extension below the seating nipple and efficient gas separation will occur. A strainer nipple can be run below the pump if desired. When the pump is run below the formation, the casing acts as the outer barrel or the "holding" chamber. Using a perforated extension below the seating nipple allows the operator to tag bottom to determine debris fillage without having to press the seating nipple into debris which could result in improper seating of the pump. The extension can be a perforated sub or a perforated sub with a Joint of tubing below the perforated sub.

A bull plug is placed below the bottom collar or preferably the bottom of the assembly is orange-peeled. Sometimes, a dip tube is run below the pump on the inside of the perforated sub in an attempt to make the gas separator more efficient. Running a dip tube below the pump should not be performed. The additional friction losses result in less efficient operation. Please refer to Figure I which shows such a gas separator assembly. The figure on the left shows the perforated sub and tub ing extension below the seating nipple. A dip tube is placed in the gas separator assembly. On the right side, a single dip tube is shown which is made from a perforated sub that is orange-peeled on the bottom to reduce the possibility of sand entrapment. A dip tube on the inside of the perforated sub is not needed because the perforated sub assembly is acting as a dip tube on the inside of the casing and the area is greater between the casing and O.D. of the perforated sub than between the I.D. of the sub and the O.D. of any inner dip tube.

A natural gas separator assembly is shown on the left of Figure 2. On the night, a higher capacity natural gas separator is shown. If the liquid capacity of the tubing size natural gas separator does not equal or exceed the pump capacity, the higher capacity natural gas separator should be considered. A dip tube is run below the pump of sufficient size so that friction loss within the dip tube is less than 1/2 PSI. The dip tube extends at least five feet below the fluid entry zone. Note that the area between the dip tube and the casing is greater on the right than on the left and this additional area will result in additional gas free liquid capacity. Whenever possible, the pump and/or dip tube should be set below the formation since the downward velocity of liquid will be less in this configuration and better gas separation will occur than any other type of gas separator which can be run into the well.

Gas bubbles rise in most produced, low-viscosity (<10 cp.) liquids at a rate of 6" per second. Thus, each square inch of area between the dip tube and the casing wall allows approximately 50 barrels per day of liquid to fall gas free down to the inlet of the pump. See Table I for capacities of natural gas separators with the pump below the formation. A 2-3/8" perforated tubing sub below the formation inside of 4-1/2" casing has a capacity of 410 BPD. A 1-1/4" dip tube below the seating nipple will increase the capacity to 520 BPD.

CONVENTIONAL GAS SEPARATOR ABOVE THE FORMATION

Most often, gas separators that are set above the formation are made from common oilfield materials that include thick wall tubing or pipe capable of withstanding differential pressures exceeding 2000 PSI. The thick wall of conventional tubing or conventional perforated subs reduces the area available for separating gas from liquid which decreases the capacity of the gas separator by approximately 50 BPD. Also, the outer diameter of the perforated sub is less than the diameter of the collar. This further reduces the area between the inside of the perforated sub and the internal dip tube and hence reduces the liquid capacity. See Table 2 and Figure 3. Note that the liquid capacity of a conventional 2-3/8" gas separator with 1-1/4" dip tube is only 50 BPD. Probably the main reason that the conventional gas separator has a perforated sub that is smaller in diameter than the collar is that the perforated sub is easy to manufacture from a short Joint of tubing that is perforated rather than a manufacturer's attempt to design an efficient gas separator. The perforated sub gas separator is often called a "Poor-Boy" gas separator.

Another problem with conventional gas separators is that most of the gas separators utilize small 1/4" or 3/8" holes or narrow slots for fluid entry from the casing annulus into the gas separator. When the pump is on the upstroke, liquid is drawn into the pump and a differential pressure exists between the casing annulus and the interior of the gas separator causing fluids to flow into the gas separator.

Whatever ratio of gas and liquid that exists outside of the perforated sub will flow into the gas separator. Often, the gaseous liquid column surrounding the gas separator contains more than 75% free gas[1]. Thus, considerable amounts of gas flow with the liquid into the annulus of the gas separator. Since the inside of the gas separator has a lower pressure than the casing annulus when the pump is on the upstroke, very little if any gas is discharged from the gas separator into the casing annulus on the upstroke. On the downstroke, liquid flow into the pump ceases. The pressure on the inside of the gas separator rapidly approaches the pressure on the outside of the gas separator in the casing annulus. If a 4' perforated sub is utilized, the difference in pressure in the casing annulus between the top perforation and the bottom perforation is often less than 0.4 PSI due to a gasified liquid column in the casing annulus. The pressure inside the perforated sub near the midpoint will be approximately the average of the pressures in the casing annulus opposite the top and bottom perforations in the perforated sub. At the lower most perforation of the sub, the pressure in the casing annulus will slightly exceed the pressure on the inside of the gas separator and small amounts of both gas and liquid will flow into the gas separator. The gas pressure on the inside of the gas separator at the top perforation will slightly exceed the pressure on the outside of the gas separator, and gas will flow at a low rate from the inside to the outside of the gas separator. When a conventional perforated sub is used, most of the liquid and gas inflow into the gas separator occurs on the upstroke. Most of the gas discharge from the gas separator to the casing annulus occurs on the downstroke. Thus, many conventional, perforated sub, "Poor-Boy" gas separators operate at low efficiency. This fact has been verified by hundreds of tests.

COLLAR-SIZE GAS SEPARATOR ABOVE THE FORMATION

When the pump is above the formation, a balance should be designed into the gas separator system so that the friction loss in the dip tube is kept to a minimum, preferably less than 1/2 PSI. Also, the downward flow rate of liquid in the gas separator annulus between the outer barrel and the dip tube should be less than six inches per second. Free gas will be liberated from most produced liquids if the downward flow rate of the liquid is less than 6 inches per second. The third consideration is the space between the outer barrel of the gas separator and the inside of the casing. Sufficient space should exist so that the gas flow rate around the ports in the gas separator will allow liquid to flow or “fall” into the gas separator annulus. Upward gas flow rates in excess of approximately 10 feet/second will lift the liquid and "mist" flow occurs.[14] If the outer barrel of the gas separator fits too closely into the casing I.D., excessive casing annulus gas flow rates will prevent the liquid from flowing or “falling” into the gas separator annulus. It is thus necessary to balance the available wellbore space between the area required surrounding the gas separator in the casing annulus which is a function of the gas velocity, and the area required inside the gas separator, which is a function of pump capacity.

Several advantages exist for the gas separator outer barrel being the same diameter as the tubing collar. Some operators are hesitant to run a gas separator into a well that the diameter of the gas separator exceeds the diameter of the tubing collar because of potential retrieval problems. Having the gas separator O.D. the same as the tubing collar O.D. will help to prevent sand fill around the bottom collar which might hinder removal of conventional perforated sub or oversized gas separators.

Another reason for a collar-size gas separator is that at least some of the ports in the gas separator outer barrel should be near the casing wall because studies[14] have shown that where tubing touches the casing wall is an area of higher liquid concentration. The third reason for an outer barrel being the same diameter as the tubing collar is that when a smaller O.D. tubing joint is perforated and used as the outer barrel, the smaller area between the dip tube and the inside of the perforated sub limits the liquid capacity of the gas separator and often results in incomplete pump fillage even when liquid exists above the pump in the casing annulus. Thus, a thin-wall, high liquid capacity, gas separator with the

O.D. of the outer barrel being the same diameter as the collar should probably be used in a majority of wells (where the pump is above the formation) that produce over 100 BPD (and free gas) to increase pump fillage See Figures 4 & 5.

A thin-wall outer tube permits an increase in the gas separator liquid capacity. However, even when the pump is set above the formation, the problem sometimes exists of setting the gas separator down onto sand and collapsing the gas separator. The collar-size gas separator with large ports and 1/8" wall has a collapse strength approximately 7596 of conventional tubing. However, just this decrease in wall thickness increases the capacity of the gas separator approximately 50 barrels per day over conventional tubing wall thickness. The same principle is also involved in the dip tube. The differential pressure across the dip tube is less than 1 PSI, and a thin-wall, dip tube should be used for additional capacity. A smooth, thin-wall, 316 stainless steel, schedule 10, seamless, dip tube is recommended especially if corrosion exists. See Table 3 for capacities of standard and thin-wall dip tubes. Note that the capacities should be derated for beam-pump wells (that flow liquid up the dip tube only 5096 of the time) because the maximum dip tube flow rate exceeds the average flow rate.

Four large ports are an important factor in the improved performance of the collar-size gas separator. The large ports allow liquid entry into the gas separator 100% of the time on both the upstroke and downstroke. The large ports allow liquid from the casing annulus to fall by gravity force into the gas separator because the pressures inside and outside of the large ports are the same. The large ports result in more liquid flow and less gas flow from the casing annulus to the inside of the gas separator. See Figure 4. Four large ports are cut into the outer barrel of the gas separator. Two upper ports are immediately below the collar on opposite sides. These ports are 4" high and of sufficient width so that the area of the port is equal to or exceeds the area on the inside of the gas separator between the outer barrel and the dip tube. Two inches below the upper ports, two lower ports are cut at right angles to the upper ports. The total port area is approximately four times the area on the inside of the gas separator.

Earlier studies [12,14] have shown that liquid concentrates where tubing is placed against the casing wall. Thus, the gas separator ports should lay against the casing wall. This separator should not be run immediately below a tubing anchor as the ports on the gas separator will not be against the casing wall where an increase in liquid concentration will exist. At least two joints of tubing should be run between the tubing anchor and the collar-size gas separator. This spacing should cause the separator to lay against the casing wall due to gravity forces.

Visual studies at the University of Texas in clear casing/tubing test facilities[12] and also downhole video camera studies [15] indicate that gas tends to flow up on the high side of the casing annulus. Most wells have some deviation, and the fact that gas tends to concentrate on the higher side of the casing should be utilized whenever possible by allowing the gas separator to lay by gravity forces against the low side of the casing where the liquid concentration is higher. This results in greater liquid flow into the interior of the gas separator. One advantage of the collar-size gas separator over the decentralized gas separator[16] is that the collar-size gas separator always lays against the low side of the casing while the decentralized gas separator ports may be held against the high side by the spring.

GAS SEPARATOR LENGTH

Another factor to consider is the length of the gas separator. Many previous designs utilize from one to three pump volumes as the proper volume to contain in the gas separator between the inlet ports and the lower opening on the dip tube. However, visual studies[12] performed on laboratory wells clear casing and clear gas separator indicate that the rate at which gas bubbles migrate upward in the liquid column and the pumping speed should be the controlling factors. If a well is pumping 10 strokes per minute, the pumping cycle time is 6 seconds. Three seconds occur on the upstroke and three seconds occur on the downstroke. If gas bubbles are drawn down into the gas separator annulus during the upstroke, these gas bubbles are most apt to be liberated when the pump is on the downstroke. On the downstroke, these bubbles will migrate upward at a rate of approximately 6 inches per second. If the downstroke time is 3 seconds, gas bubbles will migrate upward 18 inches. This suggests that a dip tube should extend at least 18 inches below the gas separator inlet perforations for a well pumping 10 strokes per minute. Longer distance results in additional friction losses and the release of free gas from the oil flowing up the dip tube into the pump. A Rotoflex unit operating at 4 strokes per minute has a downstroke time of 7-1/2 seconds which will allow gas bubbles to flow upward approximately 45 inches suggesting a dip tube length of 45 inches. The collar-size gas separator has a dip tube that extends about 70 inches below the bottom of the outer barrel ports.

SPECIAL CONSIDERATIONS

The collar-size gas separator is a complete unit. That is, the top collar, the outer barrel and ports, dip tube, lower half-collar and clean-out bull plug are all an assembly that functions as a gas separator and should be installed as a unit below the seating nipple. Do not install a dip tube on the pump as the correct size dip tube is already permanently mounted in the gas separator. If the wells have a history of collecting debris and sand into the gas separator, a collection chamber should be installed immediately below the collar-size gas separator. Remove the bull plug and install a nipple. Then attach a chamber of sufficient size to hold the debris immediately below the nipple.

The thin-wall, low pressure drop, high liquid capacity, collar-size gas separator is inexpensive. It is light-weight, 8 feet long and easy to transport or ship anywhere in the U.S.A. overnight.

A larger collar-size gas separator can be run than the tubing size if additional liquid capacity is desired. That is, a 2-7/8 inch collar-size gas separator can be run immediately below a 2-3/8 inch seating nipple. Attach a 2-3/8 inch collar to the bottom of the seating nipple. Attach a 2-3/8 inch by 2-7/8 inch swedge to the bottom of the 2-3/8 inch collar. Then attach the 2-7/8 inch collar-size gas separator to the swedge.

Top hold-down pumps that are used above the formation with conventional perforated sub gas separators are inefficient. Generally, the area between the inside of the perforated sub and the O.D. of the pump is less than one square inch and the liquid capacity is less than 50 BPD. The top holddown pump could be used with a collar-size gas separator by use of a joint of tubing that is slightly longer than the top hold-down pump. The joint of tubing is attached to the bottom of the seating nipple and the collar-size gas separator is attached to the bottom of the joint. Preferably, the seating nipple and top hold-down pump should be run below the fluid entry zone. The seating nipple can be run without air extension below the seating nipple if desired. If an extension is used below the seating nipple, the pump will act as a dip tube. A perforated sub that is longer than the pump could be run below (lie seating nipple. The sub should be perforated the complete length from the <u>top to the very bottom</u> with large perforations or ports for more efficient operation.

PROGRESSIVE CAVITY PUMP CONSIDERATIONS

Progressive cavity pumps perform better when the pump is subjected to liquid flow only. Th liquid lubricates and cools the polymer sealing material. Separation of free gas from the liquid entering the PC pumps will greatly increase the efficiency and prolong the life of progressive cavity pumps. Refer to Table 4. When gas is compressed, the temperature increases dramatically. For example, if the inlet to a pump is subjected to a 0.8 SG hydrocarbon gas at a pressure of 100 PSI and temperature of 100^{o}F without liquid, the outlet temperature is a function of the discharge pressure. If the well is 4,000 feet deep, the outlet pump pressure is approximately 2000 PSI. The temperature of the gas increases from 100^{o}F to 475^{o}F in a very brief period of time. This results in destruction of most Polymers if the pump is subjected to gas without liquid for only a few minutes. The collar-size gas separator improves the separation of gas from liquid and results in additional production and longer life than when a progressive cavity pump is used above the formation without an efficient gas separator. Preferably, the progressive cavity pump inlet should be run below the formation.

COLLAR-SIZE GAS SEPARATOR SELECTION

The collar-size gas separator design considers the pump capacity, dip tube liquid capacity, gas separator annular area liquid capacity, the large ports for liquid entry into the gas separator and the annular gas flow rate between the gas separator and the casing wall. The liquid capacity of a sucker rod pump can be calculated using a variety of techniques and software programs including a free wave equation software program Qrod.[17] The casing annulus gas flow rate can be determined using a strip chart acoustic liquid level instrument and surface pressure gauge [18,19] or the computerized instrument and procedure given in reference 1.

See Table 5 which shows the liquid and gas capacities for various combinations of collar-size gas separators and various sizes of casing. A 2-7/8" collar-size gas separator has a capacity of approximately 415 BPD. The pump capacity should be less than 415 BPD or the separation of free gas from the liquid may not occur and free gas will be drawn into the pump. If the 2-7/8" separator is to be used on the inside of 5-1/2" casing, the maximum casing annulus gas flow rate for efficient operation of the gas separator is approximately 51 MCF per day at 1 ATM. The gas capacities shown are for a pump intake pressure of 1 ATM. When the pump intake pressure is higher, the gas capacities shown should be multiplied by the pump intake pressure expressed in atmospheres. This limitation of 51 MCF/D would only exist if the well were produced with the casing valves open to atmosphere and liquid did not exist above the pump. Most wells are produced with casing pressures between 30 and 125 PSI that would cause a pressure at the collar-size gas separator of 3 to 10 atmospheres assuming that a limited amount of liquid exists above the pump. Thus, the capacities shown should be multiplied by 3 if the casing pressure is approximately 30 PSIG and by 10 if the casing pressure is approximately 125 PSIG. The gas capacity of the collar-size gas separator increases with the surrounding gas pressure.

A collar-size gas separator should be selected that is the same size as the tubing unless the pump capacity exceed the gas separator capacity. Then, a larger gas separator should be selected that has a liquid capacity equal to or greater than the pump capacity. At high liquid and gas rates, even an optimum size gas separator in limited size casing may not have the capacity to separate all of the liquid From the free gas at low pump intake pressures.

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GAS SEPARATOR CAPACITY TABLE
PUMP BELOW FLUID ENTRY ZONE

CASING SIZE INCH	DIP TUBE SIZE INCH	DESCRIPTION	ANNULUS* AREA SQ INCH	LIQUID CAPACITY BPD
		CONVENTIONAL		
7	3 1/2	PERFORATED TUBING SUB	23.1	1150
7	2 7/8	PERFORATED TUBING SUB	26.7	1335
7	2 3/8	PERFORATED TUBING SUB	28.8	1440
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	PERFORATED TUBING SUB	8.2	410
		HIGHER CAPACITY IF NEEDED		
5 1/2	1 1/2	PERFORATED LINE PIPE	16.4	820
4 1/2	1 1/4	PERFORATED LINE PIPE	10.4	520

*ANNULUS AREA BETWEEN CASING AND PERFORATED TUBING SUB (OR LINE PIPE)

Table 1

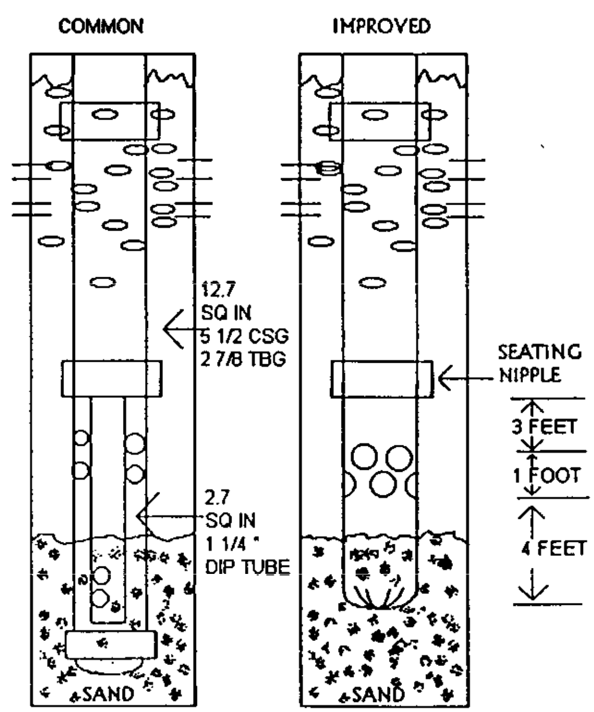

Fig. 1 Natural Gas Separators

GAS SEPARATOR CAPACITY TABLE
SEPARATOR ABOVE FLUID ENTRY ZONE

OUTER BARREL DESCRIPTION AND SIZE, INCH	DIP TUBE SIZE INCH	ANNULUS* AREA SQ INCH	LIQUID CAPACITY BPD
3 1/2 PERFORATED TUBING SUB	1 1/4	4.9	240
2 7/8 PERFORATED TUBING SUB	1 1/4	2.7	135
2 7/8 PERFORATED TUBING SUB	1	3.9	195
2 3/8 PERFORATED TUBING SUB	1 1/4	1.0	50
2 3/8 PERFORATED TUBING SUB	1	2.1	105
2 3/8 PERFORATED TUBING SUB	3/4	2.3	115
HIGHER LIQUID CAPACITY GAS SEPARATORS			
3 1/2 COLLAR-SIZE GAS SEPARATOR	1 1/4	12.0	600
2 7/8 COLLAR-SIZE GAS SEPARATOR	1	8.3	415
2 3/8 COLLAR-SIZE GAS SEPARATOR	1	4.6	230

* ANNULUS AREA BETWEEN GAS SEPARATOR OUTER BARREL AND DIP TUBE

Table 2

ADIABATIC COMPRESSION OF HYDROCARBON GAS

INLET CONDITIONS		PUMP OUTLET TEMPERATURES, F			
PRESS.	TEMP.	2000 FT DEPTH *	3000 FT DEPTH *	4000 FT DEPTH *	5000 FT DEPTH *
15 PSI	100 F	600 F	650 F	700 F	750 F
50	100	440	490	530	570
100	100	360	420	475	490
500	100	190	235	280	310
1000	100	100	150	190	225

* Pump outlet pressure (in psia) is assumed to be one-half of the well depth (in feet)

Table 4

DIP TUBE LIQUID CAPACITY

DIP TUBE SIZE, INCH AND DESCRIPTION		CAPACITY, BPD *
3/4	1.050 X 0.824 SCH 40	315
1	1.315 X 1.049 SCH 40	630
1	1.315 X 1.110 316 SS	740
1 1/4	1.660 X 1.380 SCH 40	1350
1 1/4	1.660 X 1.440 316 SS	1570
1 1/2	1.990 X 1.610 SCH 40	1930
2	2.375 X 2.067 SCH 40	3700

* The above water capacities cause a pressure drop of 0.5 PSI in 7 feet of standard schedule 40 line pipe or 7 feet of thin-wall, schedule 10, seamless, 316 stainless steel.

Table 3

COLLAR-SIZE GAS SEPARATOR GAS AND LIQUID CAPACITY

COLLAR SIZE EUE INCH	LIQUID CAPACITY BPD	GAS CAPACITY MCF/D * 4 1/2" CASING	5 1/2" CASING	7" CASING
2 3/8 (3.0" OD)	230	27	75	150
2 7/8 (3.75" OD)	415	9	51	127
3 1/2 (4.5" OD)	600	—	5	98

*GAS CAPACITY AT 1 ATM.

Table 5

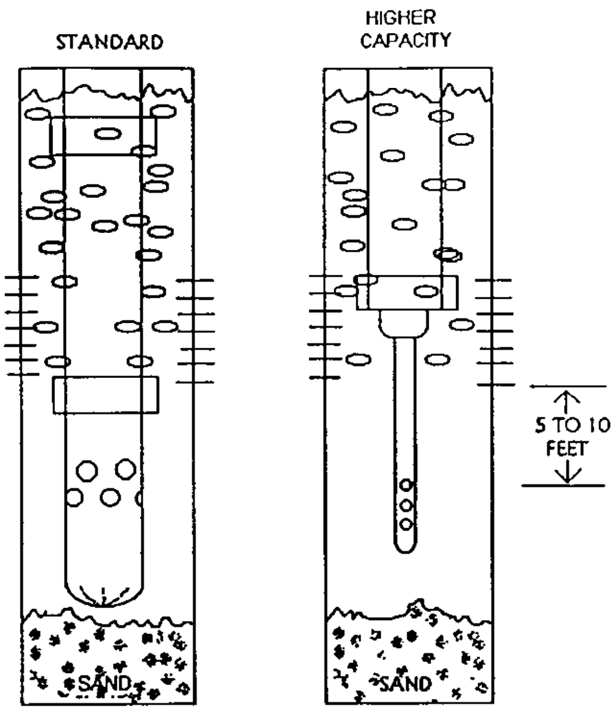

Fig. 2 Higher Capacity Natural Gas separator

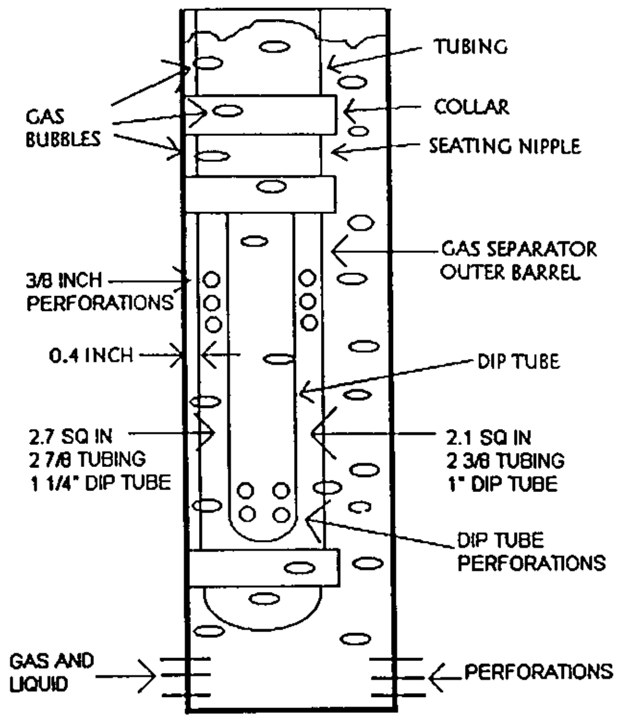

Fig. 3 Conventional Separator Above Formation

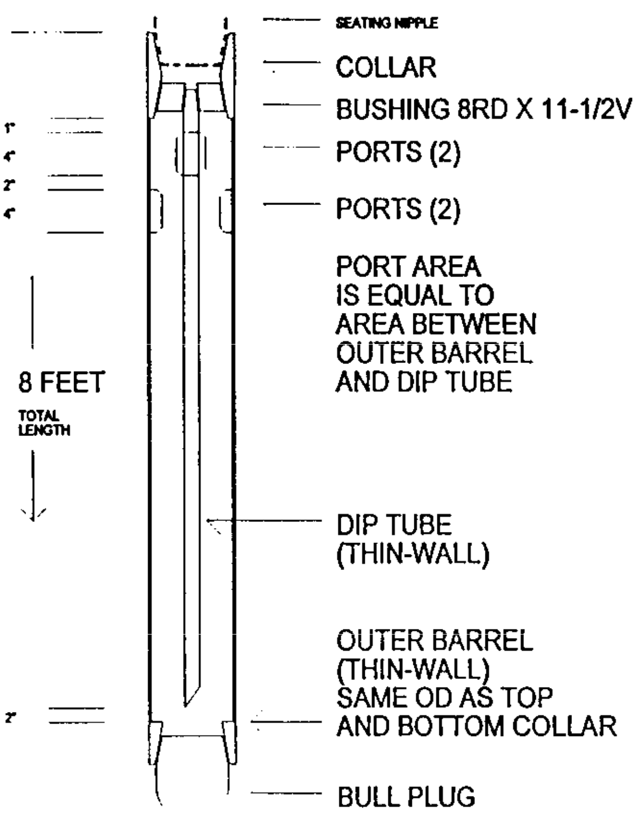

Fig. 4 COLLAR-SIZE GAS SEPARATOR DETAIL

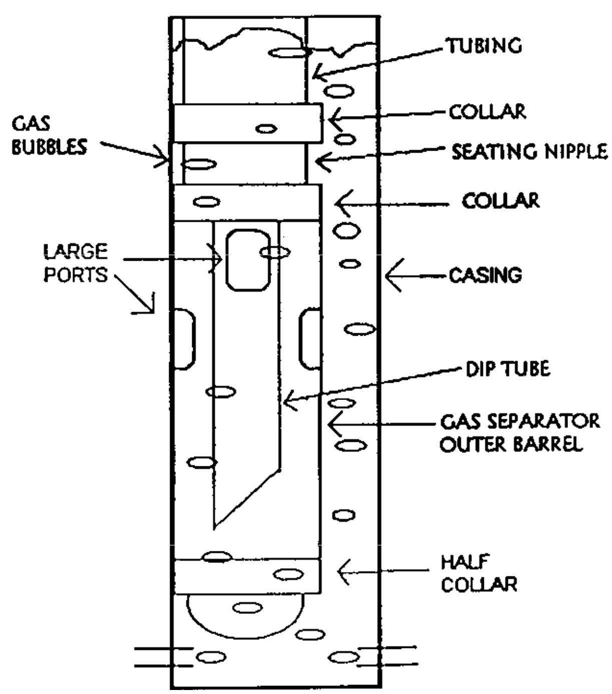

Fig. 5 Collar-Size Gas Separator in Casing