Optimizing Downhole Packer-Type Separators

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Abstract

The task of downhole gas separators has become more difficult with the advances in horizontal drilling and large fracturing technology that has resulted in many more wells that produce larger volumes of oil and gas than have been common domestically. Artificially lifting large volumes of oil and associated gas to the surface has always been a problem because of the difficulty of separating downhole oil that is to be lifted to the surface from large volumes of gas especially in rod pumped wells. Many downhole gas separators are inefficient, and the percentage of liquid in the pump is actually less than the percentage of liquid in the fluids in the casing annulus surrounding the gas separator.

This paper describes a technique for evaluating the effectiveness of different types of downhole gas separators. The new technique compares the percentage of pump fillage with the percentage of liquid present in the gaseous liquid column in the casing annulus surrounding the pump.

This paper also describes a new separator that diverts the formation fluids into the casing annulus above the pump inlet so that the liquids and gas can separate by gravity in the casing annulus. The pump seating nipple and intake are positioned within inches of the liquids that exist in the casing annulus surrounding bottom of the gas separator to reduce the pressure drop so that gas is not released from the oil that flows from the casing annulus into the pump.

The new separator can be used with a conventional packer or a special pack-off assembly consisting of elastomer cups on a tube positioned between the separator and the tubing anchor below the separator. The pressure drop across the separator is generally less than 10 psi so flexible elastomer cups can be used instead of a high pressure packer.

The packer type separator is generally used with a tubing anchor, and the tubing anchor should be positioned immediately below the separator instead of above the separator because field data indicates that the tubing anchor can cause an accumulation of gas below the tubing anchor and liquid accumulation above the tubing anchor.

A recent complicating factor that must be considered when evaluating gas separator systems is the recent use of high clearance plungers in the pump. Large plunger clearances for overcoming sand problems are common in some areas that result in pump leakage of 50 % of the pump capacity, so the pump appears to be full or almost full when actually the liquid in the pump is circulated liquid that is bypassing the plunger. Field data has been measured and obtained where the pump chamber is full, but the production in the tank is negligible. The operator may think the separator is acting efficiently, but the high pump fillage results from plunger leakage and not good separator performance.

Tail pipe can be used in some wells where the pump is positioned a considerable distance above the formation to increase the well's production and reduce the producing bottomhole pressure.

The paper describes gas separation techniques and presents field data and analysis on Packer-type Downhole Gas Separators and Natural Gas Separators.

Principle of Downhole Gas/Liquid Separation

Gravity is almost always used to separate free gas from liquid in a well having a downhole sucker rod pump. The principle of gas being lighter than liquid causes the free gas to rise. A free gas bubble having a diameter of approximately ¼ inch rises about 6 inches per second in medium gravity crude oil or water, and the 6 inch per second rise time is often used in designing downhole gas separators. Therefore, if the liquid is flowing downward at a rate less than 6 inches per second, the downward flowing liquid will be relatively gas free. See Figure 1. A good downhole separator will separate the liquid from the free gas and direct the liquid into the pump. The separator is inefficient when the pump is not full of liquid and a gaseous liquid column exists above the pump.

Natural Gas Separator

The Natural Gas Separator is the most efficient type of downhole gas/liquid separator that is commonly used. See Figure 2. 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 in the annulus below the perforations is less than the upwards slip velocity of the gas bubbles present in the annular volume between the perforations and the pump intake. Natural Gas Separators are the most efficient type of downhole separators.

Table 1 lists the most common casing and tubing combinations with their respective annular areas and the resulting liquid capacities of the corresponding natural gas-liquid separators. 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 free gas into the pump intake.

Packer-type Separators

To simulate a Natural Gas Separator, a packer can be used above the formation with a separator that is configured to receive the well fluids from below the packer and discharge the fluids into the casing annulus near the top of the separator. Then the packer-type separator performs like a Natural Gas Separator where the large casing annulus is used to separate the free gas from the liquid. Figure 3 shows a conventional Packer-type gas separator described in literature in the 1950s. See references 7, 8 and 9 for available commercial packer type separators.

Poor-Boy Gas Separators

Some operators do not want to set the pump below the formation yet the well produces a lot of gas and oil. Then a conventional separator can be run into the well that contains a chamber and a dip tube which is installed below the pump seating nipple. Many variations of the Poor-Boy or Modified Poor-Boy separators exist having many different diameters of the outer chamber, different wall thicknesses, different lengths, different port openings and different sizes and lengths of dip tubes. Many are very inefficient and many do not extend the dip tube below the outer barrel perforations so the separator is almost worthless. Often the gas and liquid drawn into the pump consists of the same concentration of gas and liquid that exists in the casing annulus. See reference 1 for information on a Modified Poor-Boy gas separator having the OD of the outer barrel the same diameter as the collar that offers good performance in medium capacity wells[6].

One of the most common problems in gas separation when the pump is set in or above the formation is the use of a perforated joint below the pump without the use of a dip tube below the pump inlet that extends at least 18 inches below the joint's perforations. The result is the drawing of liquid and gas into the perforated joint during the pump upstroke which often consists of more gas than liquid. The gas and liquid are not separated so the gas and liquid that enter the perforations also enter the pump. Sometimes, a short perforated nipple is used below the pump inlet that does not extend below the joint perforations so the nipple does not function as a gas separator from the liquid. This practice is very common and results in a substantial loss of production and higher operating costs.

Incomplete Pump Fillage

Three causes of incomplete pump liquid fillage have been identified: 1) gas interference, 2) pumped off conditions and 3) pump intake obstruction[2].

1- Gas Interference:

The fluid present at the pump intake consists of a mixture of free gas and liquid and consequently both phases enter the pump through the standing valve. This condition is normally labeled "gas interference". The separator is inefficient.

2- Pump Off

Incomplete pump liquid fillage occurs when the production liquid rate from the reservoir is less than the pump displacement rate and consequently after flow stabilization there is not sufficient liquid in the annulus to fill the pump barrel. Annular fluid level is at the depth of the pump intake. This condition is normally labeled "pumped off". The separator is operating efficiently.

3- Flow Restriction

The flow rate of liquid entering the pump is restricted so that the liquid cannot fill the pump barrel fast enough during the plunger upstroke. Flow restriction may be caused by deposits of scale, paraffin, sand, rust or other materials or by mechanical configurations such as small inside diameter mechanical hold down pump assemblies. Some separators have very long, small dip tubes that cause considerable pressure drop and release of free gas when the plunger is rising at a rate exceeding 100 inches per second. This condition is normally labeled "choked pump" and the separator is inefficient.

The condition of gas interference in rod pumped wells can be established with adequate certainty by acquiring and combining acoustic fluid level and dynamometer measurements obtained while the pumping conditions in the well have been stabilized and are representative of the normal mode of operation. Quality control of all the data and interpretation of results is also of paramount importance to be able to generate valid conclusions.

Field results of Natural and Packer-Type Separators

A field study was conducted to measure and understand the behavior and performance of Natural and Packer Type gas separators. Figure 4 shows the performance of the gas separators by plotting the percentage of liquid in the pump determined from dynamometer analysis in comparison to the percentage of liquid in the casing annulus determined from fluid level analysis surrounding the tubing near the pump.

The results were very interesting in that often the percentage of liquid in the pump is less than the percentage of liquid present in the casing annulus. Figure 5 is a full scale plot of the data. As shown, sometimes the packer-type separators are inferior to Natural Gas Separators even though the principle of operation appears to be similar.

The Packer Type Ported Coupling Separator[7] data was plotted without the Natural Gas Separator data and is shown in Figure 6. Note, that in several wells, the concentration of liquid in the pump is less than the concentration of liquid in the casing annulus.

Packer Type Separator Optimization

In an attempt to optimize the Packer Type Separators, several modifications were made to Figure 3 and the Packer Type Separators that are currently on the market. The new Seating Nipple Packer Type Separator[9] is shown in Figure 7. In Figure 3, the inner connections in the separator were screwed together which necessarily results in the outer barrel being larger due to the inner collar thus reducing the separation area in the casing annulus. To improve separator performance, the separator shown in Figure 7 is welded together which results in a smaller outer diameter separator. Another factor that was addressed was the location of the pump inlet. The pump inlet and pump are located at the bottom of the separator adjacent to the high liquid concentration in the casing annulus..

If the pump and seating nipple are positioned above the gas separator fluid exit ports, a pressure drop from the bottom of the separator where the liquid inlet is located to the pump occurs, and free gas will flow into the pump chamber. Also, if the conduit or tube from the liquid in the casing annulus to the pump inlet is restrictive to flow, an excessive pressure drop occurs because of the high velocities and friction associated with the pump plunger upward movement which often approaches 80-100 inches per second on high pump capacity wells. A longer separator will cause a greater pressure drop and the release of more free gas that will fill the pump chamber instead of liquid

Comparison of Ported Coupling and Seating Nipple Packer Type Separators

The performance of Ported Coupling, see reference 7, and Seating Nipple Packer Type Separators, reference 9, was compared by plotting the percentage of liquid in the pump Vs. the percentage of liquid in the casing annulus near the separator as shown in Figure 8. The circles are the Ported Coupling Separators and the stars are the Seating Nipple Packer separators. As shown in these tests, the Seating Nipple Packer separators yield higher pump fillage and result in higher liquid production rates.

Packer Type Separator Configuration

The packer type separator requires a mechanical linkage to the casing in order to prevent packer movement. Some packers have integral mechanical latching devices to prevent packer movement. Other packers do not have these latching devices and require the use of a tubing anchor catcher. Figure 9 shows the configuration of a conventional installation of a packer type Separator using a packer with mechanical latching devices. All of the figures displaying the packer type separators in this paper are showing packers with mechanical latching devices. If the packer does not have a latching device, a tubing anchor must be used with the packer.

Packer Type Separator with Tail Pipe

When the packer separator is set a considerable distance above the formation, tail pipe can be run below the separator to reduce the gradient of formation fluids flowing to the separator. If the approximate production and gas/liquid ratio can be estimated, the size of the tail pipe can be optimized for a minimum fluid gradient. The tail pipe will reduce the pressure drop from the separator to the formation and thus reduce the producing bottomhole pressure and increase production. See Figure 10.

The amount of pressure drop for different sizes of pipe at the flow rate given is shown in Figure 11. Note that a substantial increase in production can be obtained as the formation pressure drops. The proper size of tail pipe should be calculated for different flow rates.

Packer Type Separator with Check Valve

A check valve can be used with a Packer Type Separator with several advantages or disadvantages depending upon the operator's needs. The check valve will reduce the average producing bottomhole pressure in wells that slug. Some wells are known to slug 4 or 5 times a day. If the slugs are trapped above the check valve, the producing bottomhole pressure is reduced and additional production will result. In addition, the liquid that is trapped above the separator has more time to separate and should result in almost complete pump fillage if the pump is located near the liquid in the casing annulus. See Figure 12.

Another advantage of the check valve is when diverter cups are used instead of the packer. Dumping a lubricant down the casing while running the diverter cups will cause the lubricant to collect above the diverter cups and leak through the diverter cups when the differential pressure across the diverter cups is greater than approximately 50 psi. This will cool and lubricate the diverter cups. The lubricant is no longer needed after the cups enter the static liquid column.

The check valve can also be used when the operator wants to verify that the packer is holding. Dumping water down the casing annulus will result is a column of stabilized liquid in the casing annulus if the packer is holding.

Packer Type Separator with Tail Pipe and Check Valve

The combination of the packer type separator with tail pipe and check valve offers benefits in horizontal wells that tend to slug. The tail pipe will reduce the gradient of the formation fluids and the check valve will hold the formation fluids above the separator when the fluids flow above the separator. This will substantially reduce the producing bottomhole pressure and also increase the settling time for the liquid to separate from the gas before the liquid is drawn into the pump. See Figure 13.

Packer Type Separator with Sand Screen

Some wells produce sand which can cause numerous downhole problems. Several sand screens are on the market to minimize sand problem. With a packer type separator, liquid can be dumped down the casing annulus to backwash the sand screen. See Figure 14 for an example of the location of the sand screen.

Packer Type Separator with Stinger Assembly for a Liner

Most packer type separators require a packer or diverter cups. However, many wells are completed with 7 inch casing and a 4 ½ inch liner completed in the horizontal section. The 4 ½ inch liner could be configured to accept a stinger assembly that would seal the tubing that extends into the liner. Thus a packer would not be needed as shown in Figure 15. Some type of locking device will be needed.

Packer Type Separator with Top Holddown Pumps

Top Holddown pumps are used in special applications. With the Seating Nipple Packer Type Separator, the seating assembly is located at the bottom of the separator for bottom holddown pumps. When using a top holddown pump, a seating assembly must be located above the separator with a joint between the separator and the seating assembly so that the pump intake is located within a few feet of the bottom of the separator where the liquid inlet ports to the pump are located as shown in Figure 16.

Fluid Level and Dynamometer Data on Seating Nipple Packer Type Separator

Fluid level and dynamometer data are shown in Figure 17 on a well that has the seating nipple packer type separator installed. The well produces 87 BOPD, 80 BWPD and 250 MCFPD. The well is capable of producing more fluid, but the pump is operating at capacity. To increase production, the pump displacement rate should be increased. Additional performance data on other wells is available from the authors or info@echometer.com .

Diverter Cups

Diverter cups can be used instead of a packer in some applications. The pressure drop across the separator is generally less than 5 psi, so a few cups that seal between the casing wall and the tubing below the separator that directs the formation fluids into the bottom of the separator would cause the formation fluids to flow into the bottom of the separator. A diverter cup assembly is shown in Figure 18 that attaches to the bottom of the seating nipple packer type separator and also attaches to the top of the tubing anchor. Diverter cups cannot be used with tail pipe because of the high differential pressures that will exist at the packer. A tubing anchor should be used below the separator and diverter cups.

Conclusions

Better downhole separation of free gas from liquid on high volume wells occurs when the pump intake is below the formation.

The new technique for evaluating gas separators performance is to compare the pump fillage determined from dynamometer analysis with the amount of liquid present in the casing annulus surrounding the separator determined from fluid level tests.

The new Seating Nipple Packer Type Separator results in higher pump fillage and additional production when the pump is set above the formation in high volume wells.

Higher pump fillage results in additional production and lower operating costs.

References:

1 – McCoy, J. N. and A. L. Podio,: “Improved Downhole Gas Separator,” Proceedings of the 45th Annual Meeting of the SWPSC, 1998.

2 – Mc. Coy, J. N. et al.: “The Three Causes of Incomplete Pump Fillage and How to Diagnose them Correctly from Dynamometer and Fluid Level Surveys”, Proceedings of the SWPSC, 2010.

3-Clegg, J. D.: “Get Rid of Gas Problems in those Pumping Wells,” Oil and Gas Journal, April 1963.

4-Lisigurski, O. , J. McCoy, J. Patterson, and A. L. Podio, “The Effect of Geometry on the Efficiency of Downhole Gravity Driven Separators,” INGEPET EXPL-3-OL-39, USA, 2005.

5-Podio, A. L., J. N. McCoy, M. D. Woods, Hanne Nygard, and B. Drake, “Field and Laboratory Testing of a Decentralized Continuous-Flow Gas Anchor”, Proceedings of the 46th Annual Technical Meeting of the Petroleum Society of CIM, 1995.

6-Podio, et al.: “Collar size Separator Performance and Animation”, Presented at the 2013 SWPSC.

7- Don-Nan “Patented Gas Separator” brochure from Don-Nan Pump and Supply, 2011.

8-http://www.spiritenergysolutions.com/products/spirit-gas-separator

9-www.echometer.com/products/seating nipple gas separator

Table

	Casing size (inches)	Gas Anchor size (inches)	Description of gas anchor	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

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

Figures:

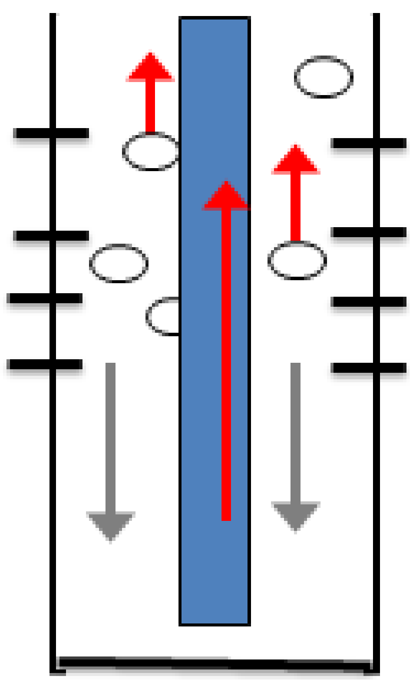

Figure 1 Gravity is the Predominate Principle of Separating Free Gas from Liquid

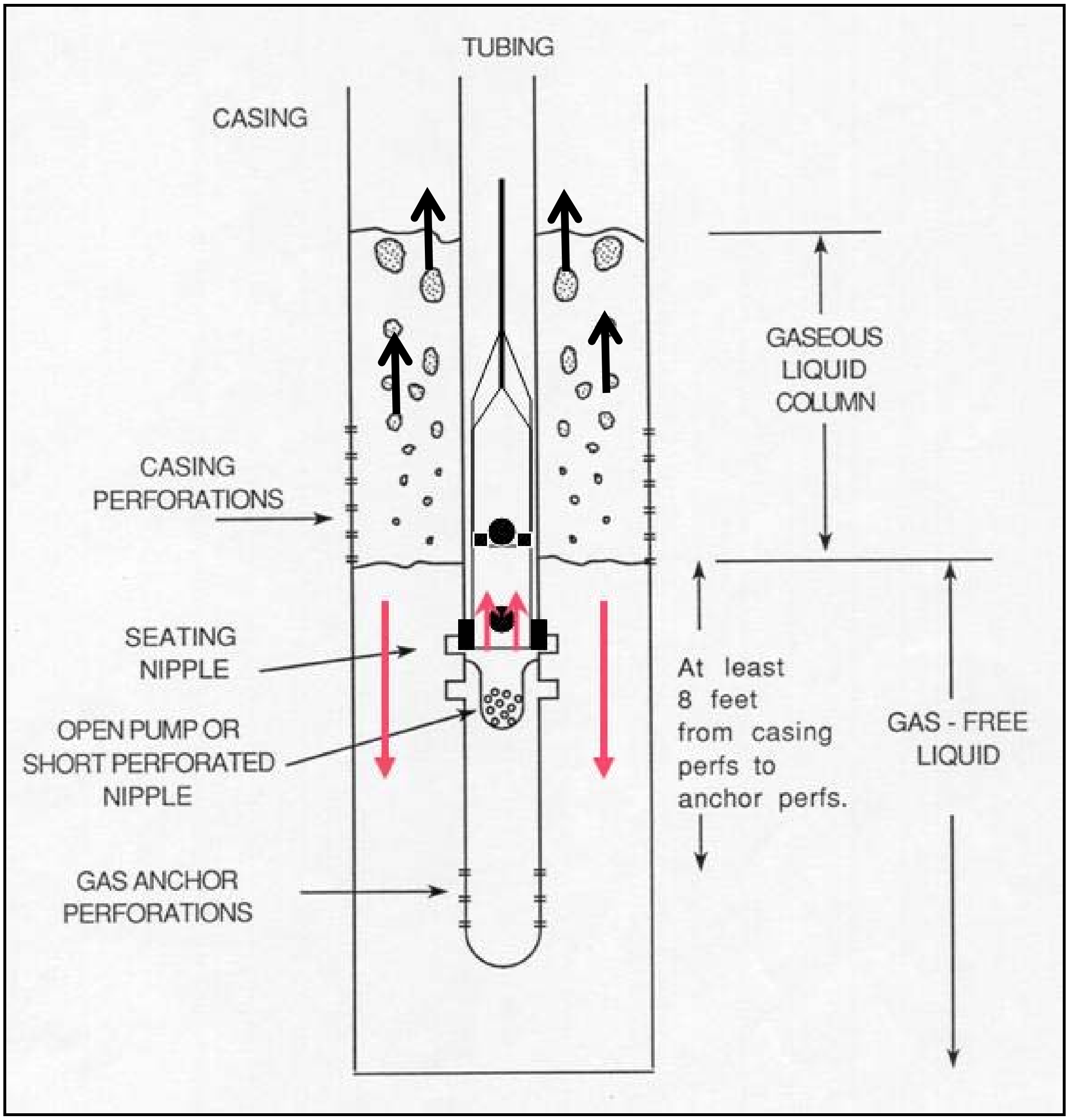

Figure 2 Natural Gas Separator

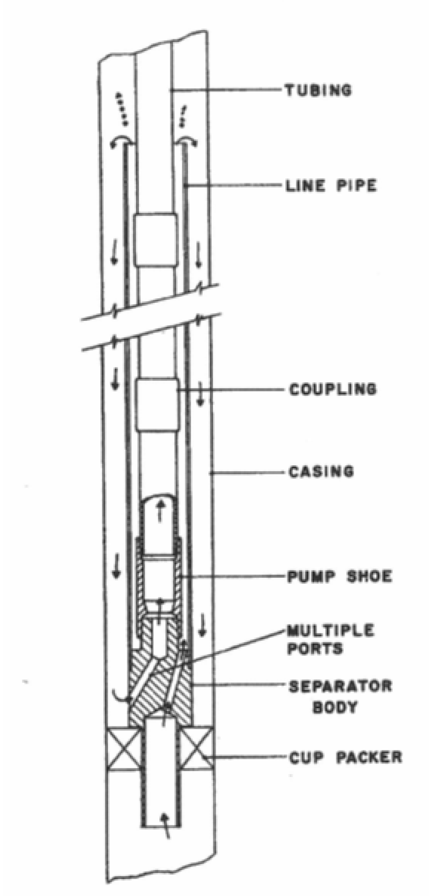

Figure 3 Packer Type Separator Using Concentric Tubes described in 1950s literature

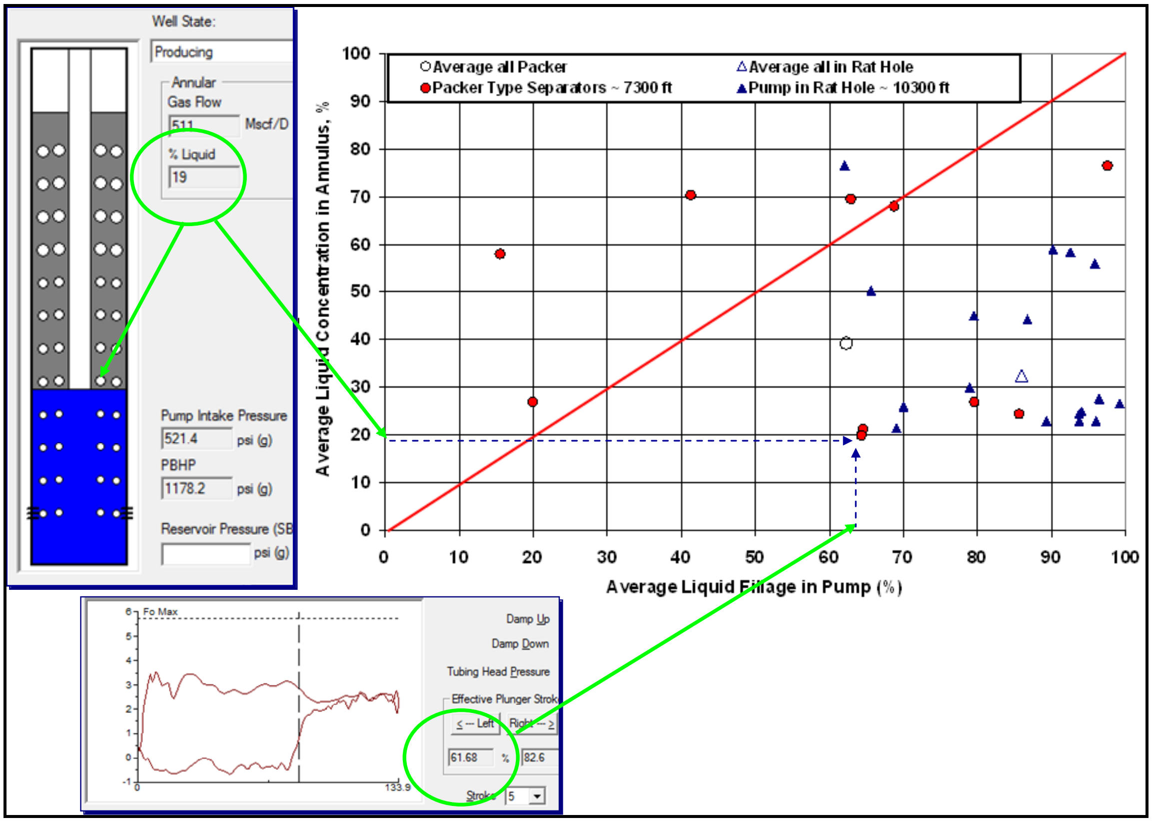

Figure 4 Gas Separator Performance Evaluation Using Pump Fillage and Casing Annulus Liquid Concentration

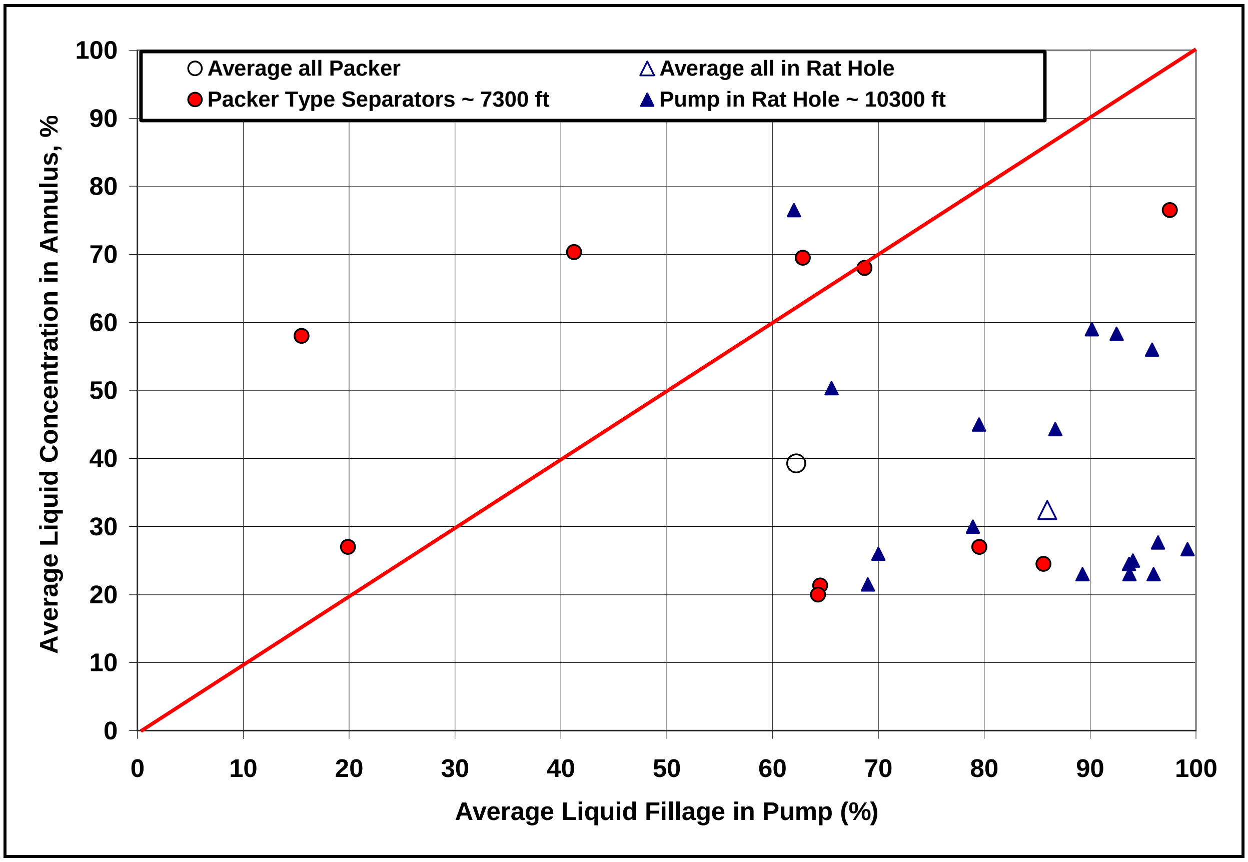

Figure 5 Natural Gas Separators and Ported Coupling Packer Type Separators Performance

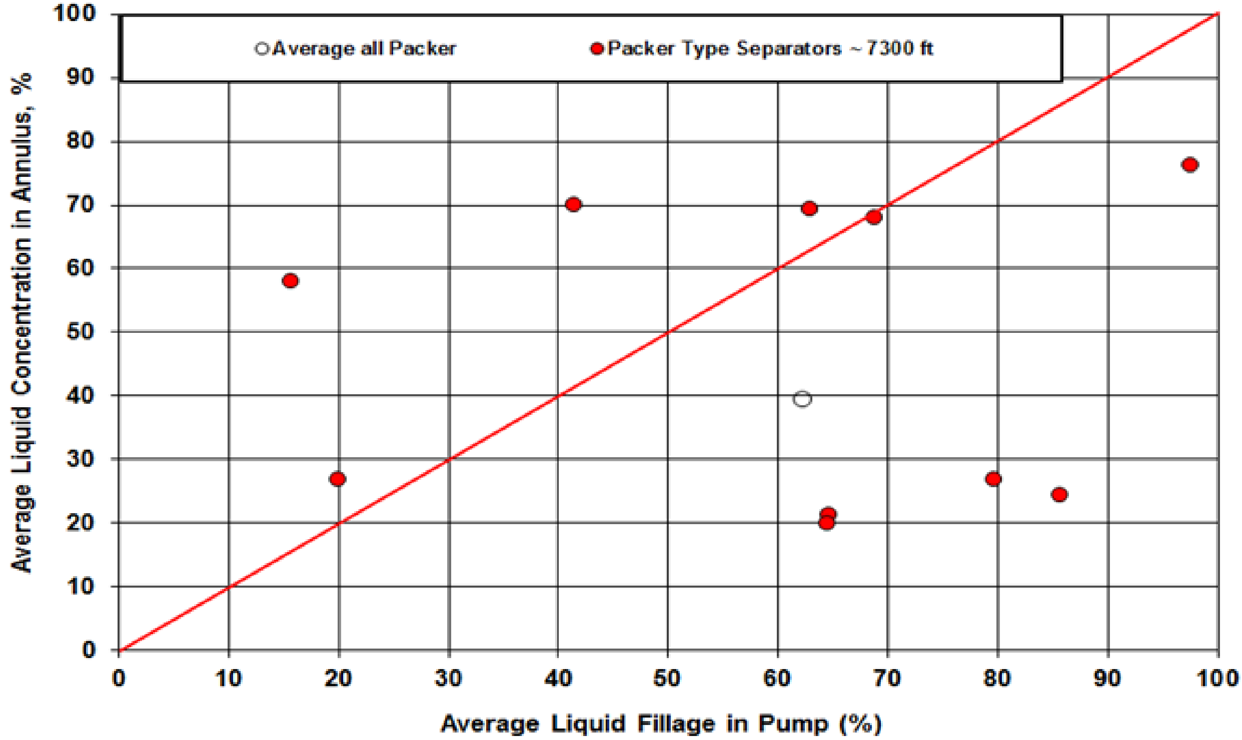

Figure 6 Ported Coupling Packer Type Separator Performance

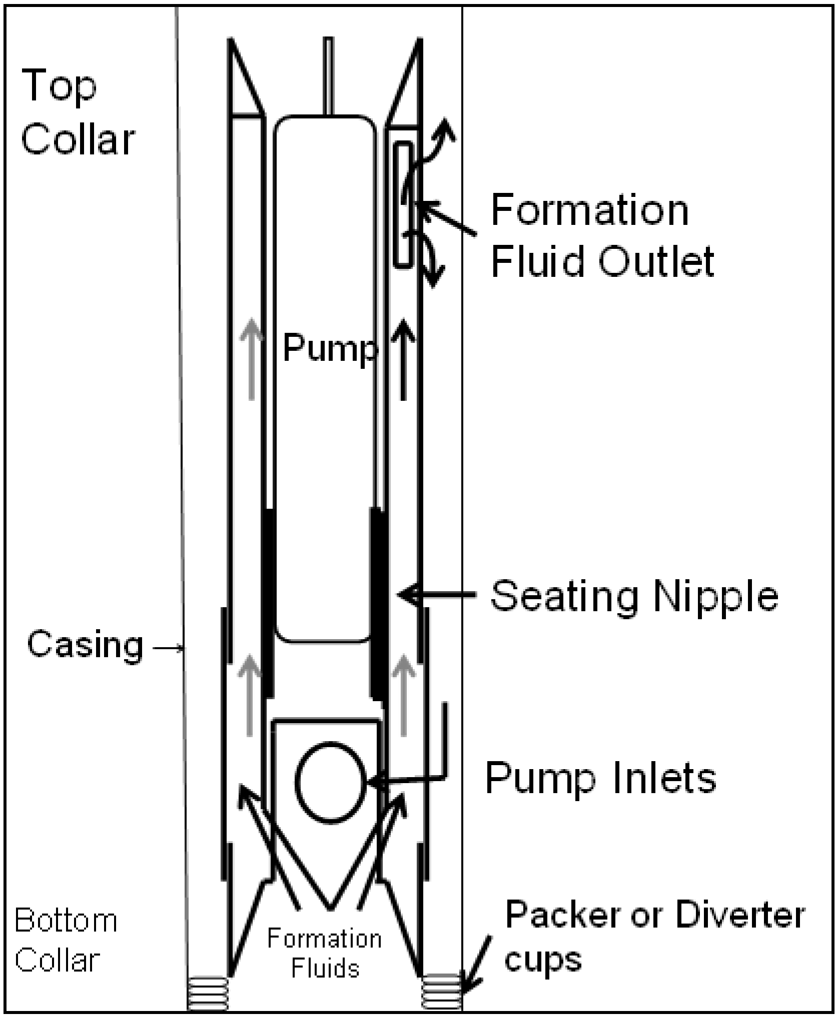

Figure 7 Packer Type Separator with Pump Located Near Liquid in the Casing Annulus

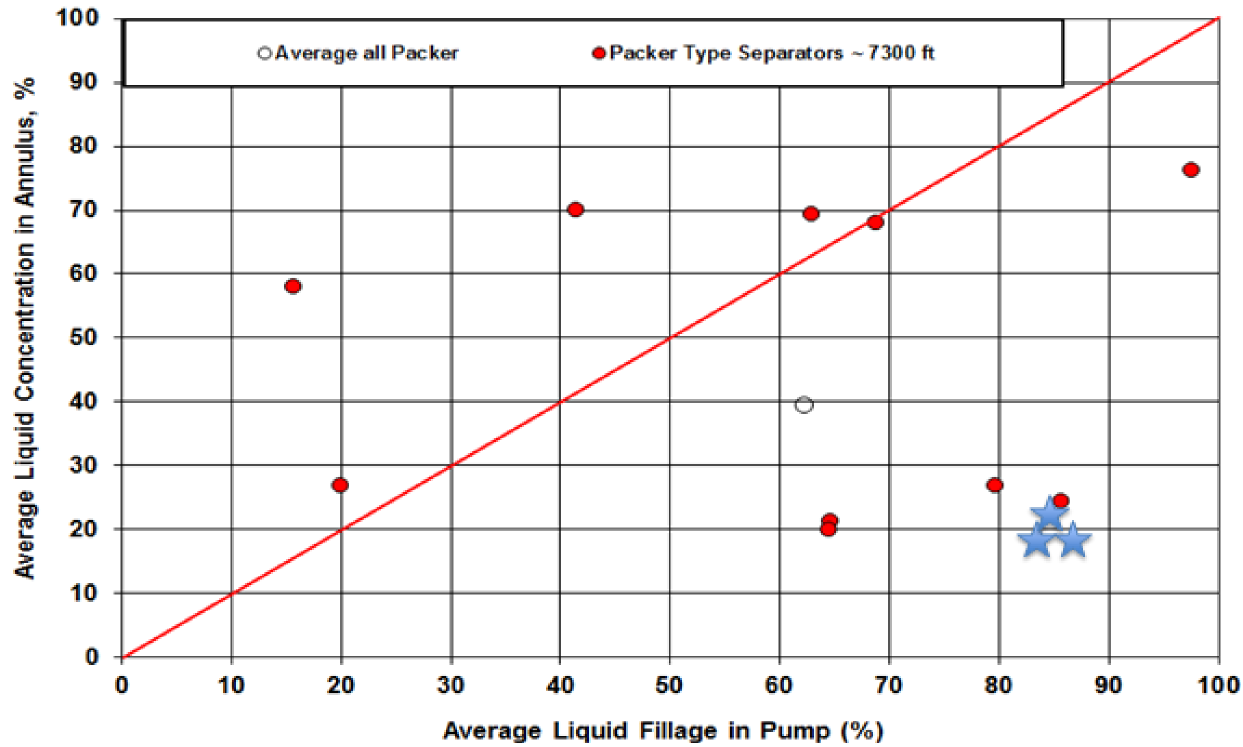

Figure 8   Packer Type Separator Performance Comparing Ported Coupling and Seating Nipple Separators

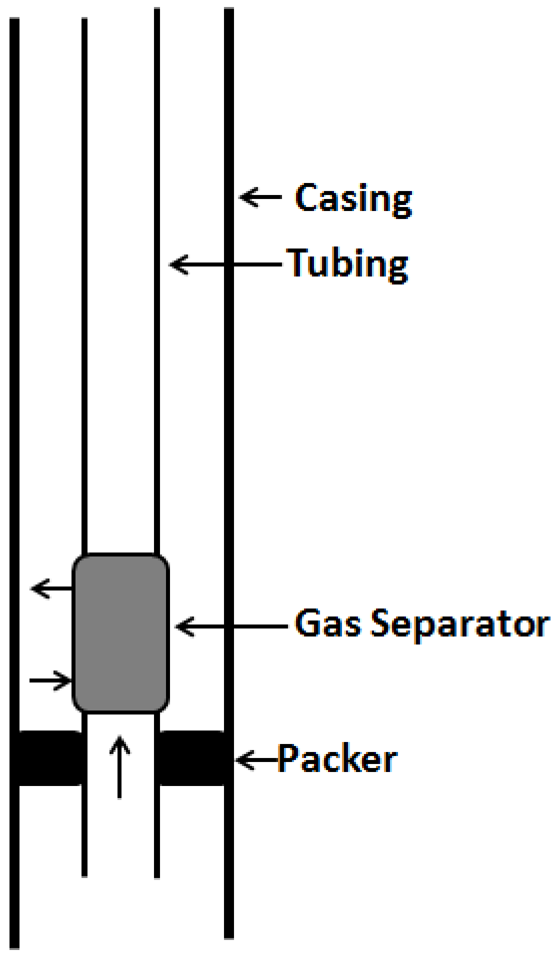

Figure 9 Packer Type Separator Configuration

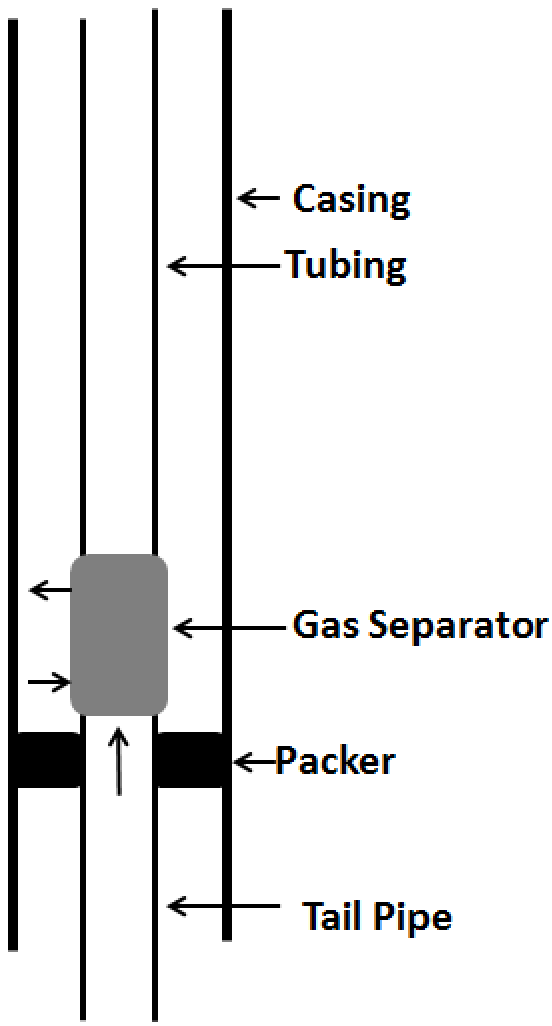

Figure 10 Packer Type Separator Configuration with Tail Pipe

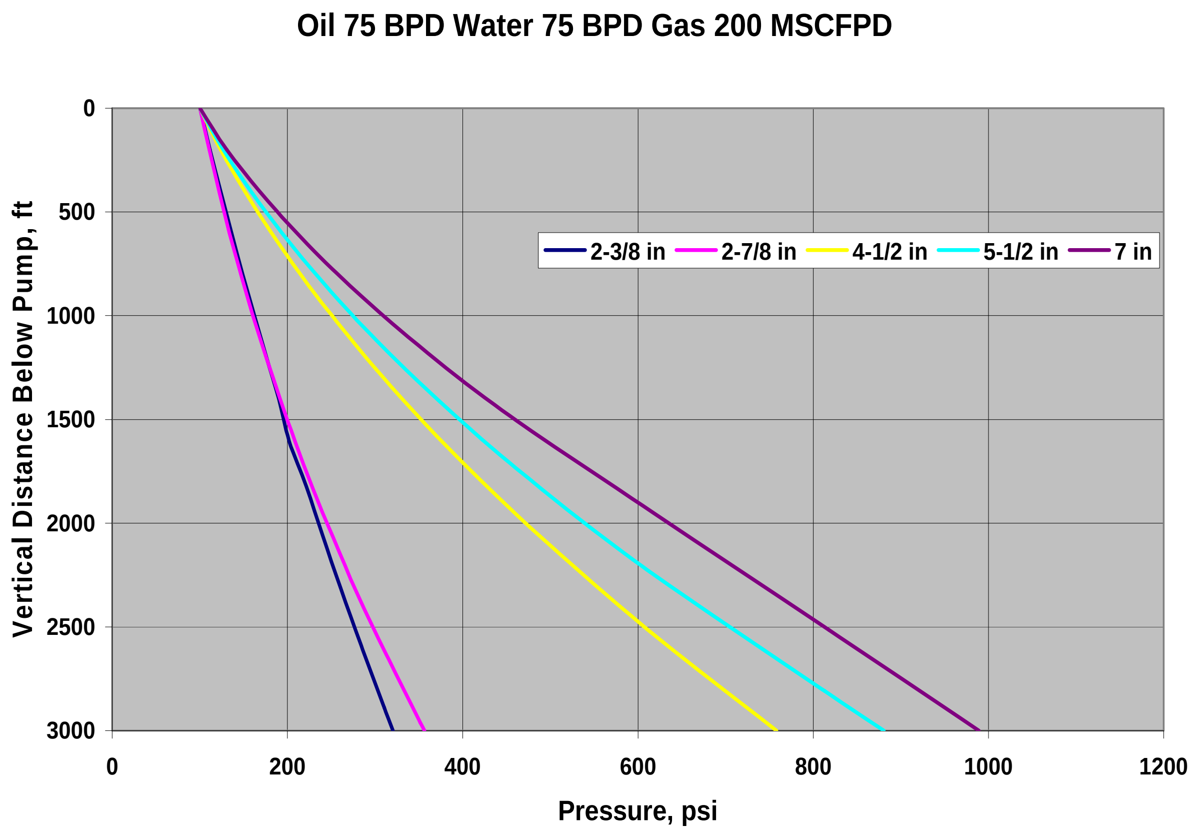

Figure 11 Gradients of Fluid Flowing at the Rates Shown for Different Sizes of Tail Pipe

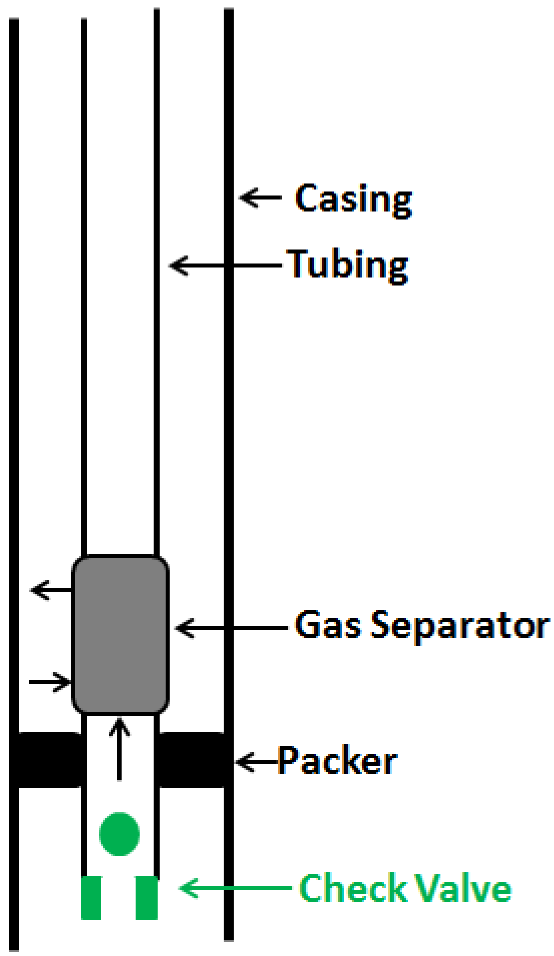

Figure 12 Packer Type Separator with Check Valve

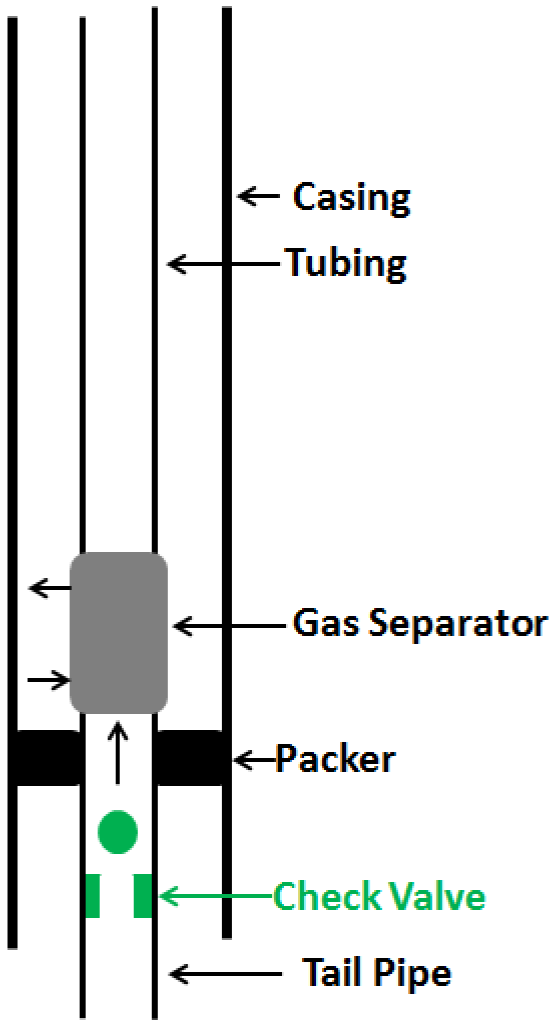

Figure 13 Packer Type Separator with Check Valve and Tail Pipe

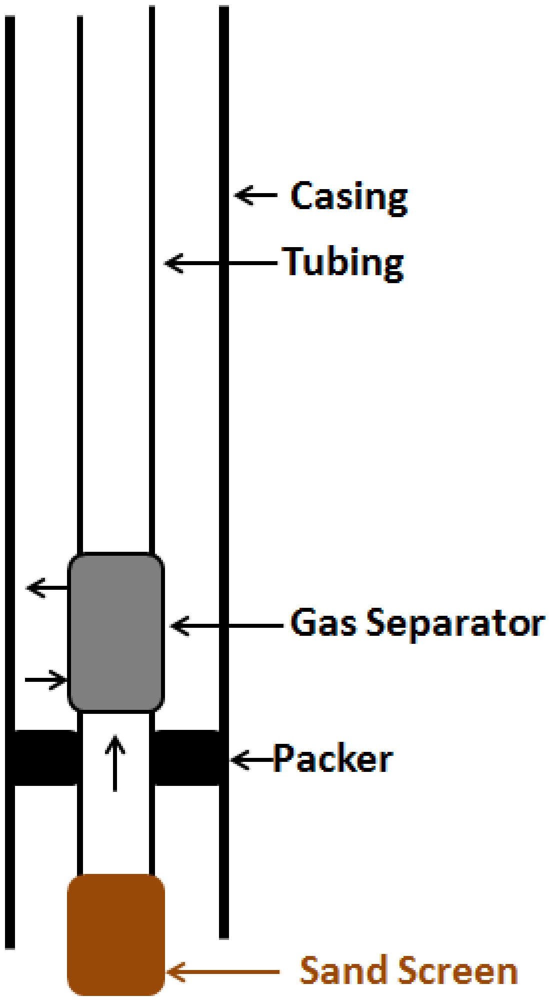

Figure 14 Packer Type Separator with Sand Screen

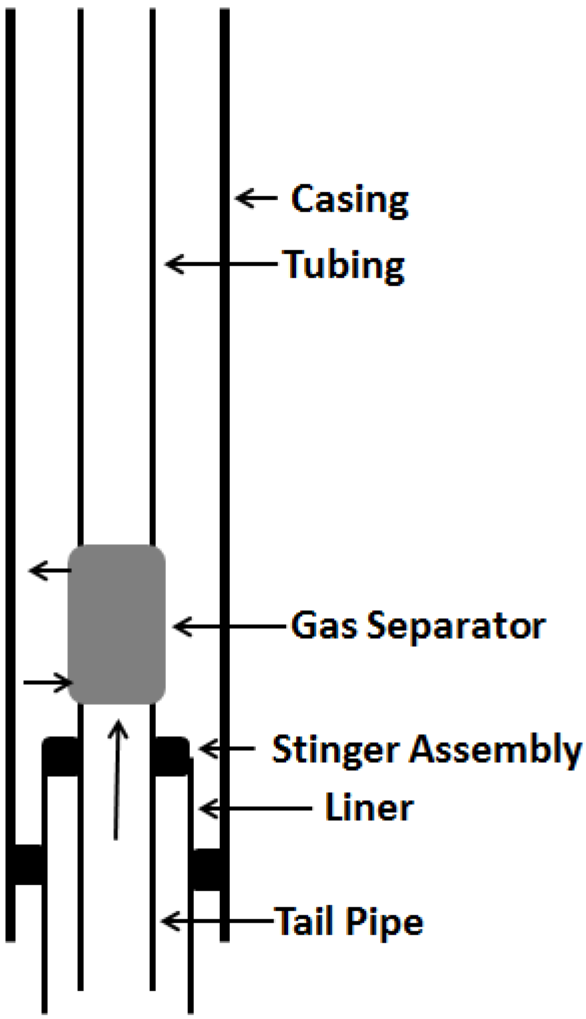

Figure 15 Packer Type Separator with Stinger Assembly for Liner

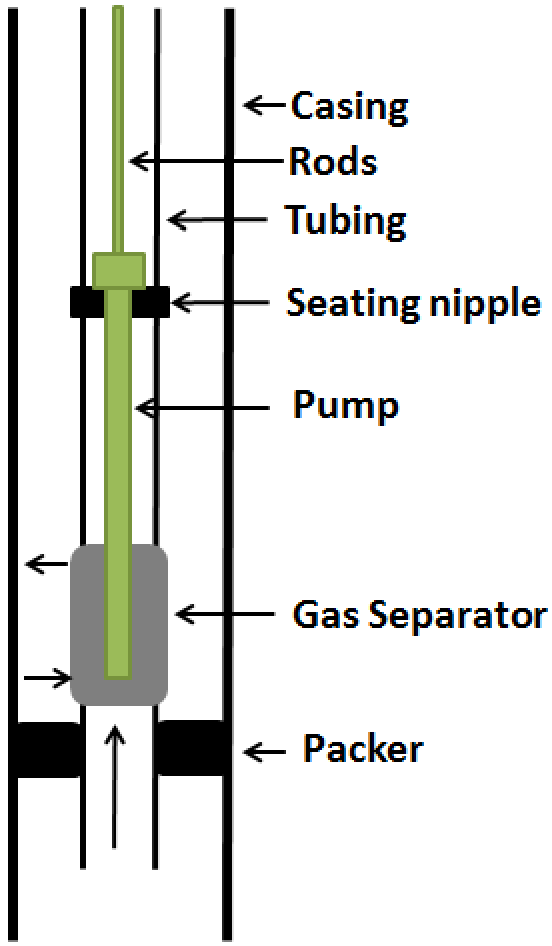

Figure 16 Packer Type Separator with Top Holddown Pump

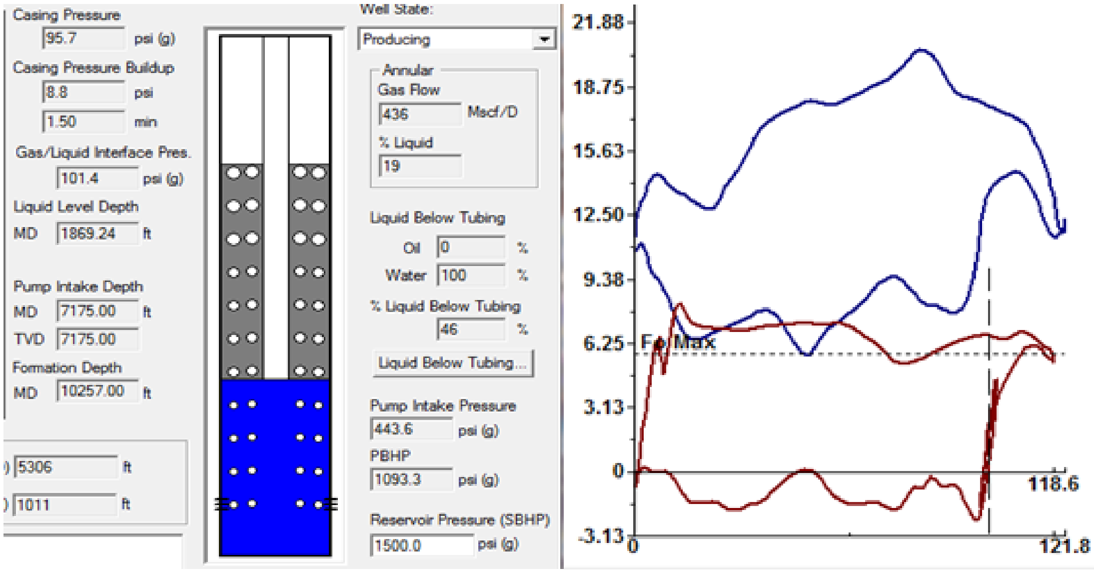

Figure 17 Fluid Level and Dynamometer Analysis of Seating Nipple Packer Type Separator Producing 87 BOPD and 80 BWPD and 250 MCFPD

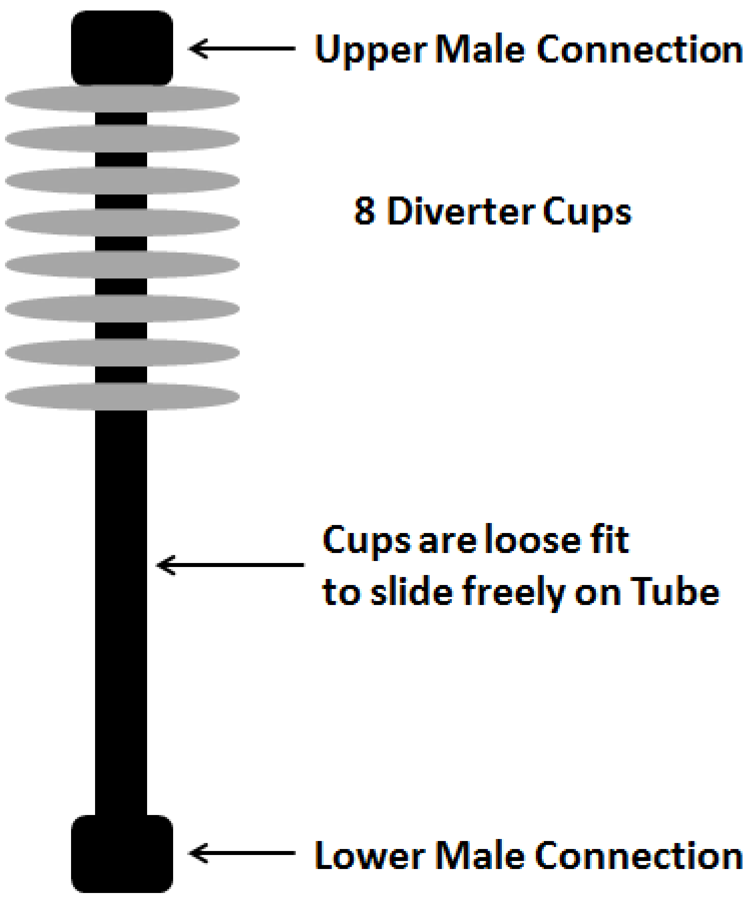

Figure 18 Diverter Cups instead of Packer for use with Seating Nipple Packer Type Separator