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Evaluation and Performance of Packer-Type Downhole Gas Separators

J.N.McCoy, Echometer Company; A. L. Podio, University of Texas; O.L. Rowlan, D. Becker, Echometer Company.

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Abstract

Advances in horizontal drilling and large fracturing technology have resulted in many more wells that produce larger volumes of oil 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 techniques for evaluating the effectiveness of downhole gas separators. Often times, the evaluation of a separator's performance is based on pump fillage and the total gas production from the well instead of the amount of gas present in the gaseous liquid column that exists in the casing annulus surrounding the pump.

This paper also describes a separation technique that diverts the formation fluids into the casing annulus above the pump inlet so that the liquids and gas can separate by gravity. A seating nipple is positioned within inches of the liquids that exist in the casing annulus surrounding 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 chamber. If the pump seating nipple is positioned above the gas separator fluid exit ports, a pressure drop in the liquids entering the pump occurs and gas will be released 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 associated with the pump plunger upward movement which often approaches 80-100 inches per second on high pump capacity wells.

The separator design can be used with a conventional packer or a special pack-off assembly consisting of elastomer rings 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 rings can be used instead of a high pressure packer.

The 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 considerable 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 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 when the high pump fillage results from plunger leakage and not good separator performance.

The paper describes gas separation techniques and presents field data on several types of downhole gas separators.

Introduction

The majority of published studies¹⁻²² 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 annular 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 in the annulus below the perforations does not exceed the upwards 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 pump intake. The disadvantage of these types of separators is that they can only handle smaller gas and liquid rates 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.

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 1.

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 casing annulus 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 are transported by the liquid into gas separator perforations while larger gas bubbles flow upward through the gaseous liquid column and ultimately vent out at the gas-liquid interface. Even when the intake is set below the perforations, if the liquid velocity exceeds the slip velocity of a gas bubble of a given size, the gas bubble will be entrained downward 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.

The Wellbore as a Gas/Liquid Separator

In a pumping well operating at stabilized conditions (constant liquid level and casing head pressure) where tubing is present it is normally considered that the fluids in the wellbore are distributed according to their respective densities: the gas in the upper part of the wellbore, a gas-liquid mixture between the fluid level and the perforated interval and only liquid below the perforated interval.

Whenever gas and liquid are flowing from the formation into the well the location of the pump intake relative to the perforations determines whether there will be a gas-liquid mixture or mainly liquid entering the pump. When the pump intake is set above the perforations liquid and gas will enter the pump. When the pump intake is set below the bottom perforated interval then mostly liquid will enter the pump.

This is the basis for using "Natural Gas Separation" to minimize gas interference in the pump as shown in Figure 1. The assumption is that the velocity of the liquid flowing downwards from the perforations to the pump intake is less than the slip velocity of the gas bubbles that are rising due to their buoyancy. 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. Experimental data²² 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.

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. 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 1. When the liquid downward velocity is equal to the design velocity of 6 inches per second for a given annular cross sectional area the corresponding liquid flow rate is computed by multiplying the flow area in square inches by 50 Bbl/day. 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. Since the gas-liquid mixture includes bubbles smaller than ¼ inch diameter that have slip velocities smaller than 6 inches per second when the pump is operating at the flow rate listed in the table the pump fillage will not be 100% but should be above 90%. When the liquid velocity in the annulus exceeds the limit (six inches/sec), also the larger gas bubbles will eventually be dragged to the pump intake regardless of the distance from the bottom of the perforations to the pump intake. When the pump rate, corresponding to the maximum plunger travel and actual pumping speed, exceeds the value listed in the table, the pump fillage will decrease in relation to the excess flow rate above the design value. Therefore it is not correct to assume that pump liquid fillage should always be 100% just because the pump intake is set below the perforations.

Packer Separators

These types of separator were developed to try to obtain a separation capacity similar to that of a natural downhole gas separator even though the intake of the pump is located above the perforations or the fluid entry depth. One of the early designs is shown in Figure 2a. The sealing packer forces all the produced fluids (oil, water, and gas) to flow inside the small-diameter vertical riser (typically 1 1/2 inches in diameter and 30 feet long) strapped to the tubing. At the top of the riser the fluids flow out into the casing-tubing annulus above the packer. The liquids fall downward while the gas flows up to the surface, where it is produced at the casing head. The liquid intake to the pump is at the bottom via 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 but the 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). The lost area corresponds to a reduction in liquid capacity of about 88 bpd for each of the configurations listed in Table 1.

To overcome the capacity reduction caused by the strapped riser tube several alternative designs²²⁻²⁵ have been proposed. One of the most common is shown in Figure 2B that uses concentric tubes with a 1-inch tube connecting the bottom entry port to the pump intake that is located about 30-40 feet above the packer. 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 30-40 feet to reach the pump intake that is set in a landing nipple at the top of the separator assembly.

Evaluation of Separator Performance

Although downhole gas separators have been used for many years, the industry has failed to develop guidelines or standards to evaluate their performance. The most common methods are to evaluate the separator solely on the presence of surface indications of gas in the tubing, or indications of “gas locking” or “flumping” or in more sophisticated analyses based on pump liquid fillage as shown in pump dynamometer cards computed from surface dynamometer measurements. Unfortunately these methods are inconsistent and prone to yielding incorrect conclusions about the actual effectiveness of the downhole gas separator.

Three causes of incomplete pump liquid fillage have been identified: 1) gas interference, 2) pumped off conditions and 3) pump intake obstruction²⁶.

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”.

2- Pump Off

Incomplete pump liquid fillage occurs when the production liquid rate from the reservoir (flowing through perforations) 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 “pump off”

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 excessive

friction losses related to flow of viscous crude or mechanical configurations such as small flow areas long dip tubes or pump designs. This condition is normally labeled “choked pump”.

The referenced paper²⁶ lists the guidelines that can be used when analyzing dynamometer and fluid level data that permit to identify the real cause of incomplete liquid fillage.

It is therefore apparent that the efficiency of a downhole gas separator is relevant only when the cause of incomplete fillage is the presence of a gas-liquid mixture at the depth where the pump intake is located. A downhole gas separator cannot solve the problem of incomplete liquid fillage for cases 2 and 3 and its performance should not be judged when these conditions exist.

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.

Analysis of the fluid level record yields the following information:

- 1) The existence of gas flow from the annulus and its daily flow rate based on casing pressure increase vs. time.
- 2) The concentration of gas and liquid present in the annular fluid that exists above the pump setting depth.
- 3) The pressures that exist at the casing head, the gas/liquid interface, the pump intake and the producing zone.

Analysis of the dynamometer record yields the following information:

- 1) The pump liquid fillage as a percent of the plunger stroke
- 2) The average plunger displacement in bbl/day
- 3) The pump intake pressure.

The total gas produced by a pumping well is generally the combination of gas flowing up the tubing with the liquid and gas flowing up the annulus. Only the gas flow rate up the annulus is an indication of the potential for gas interference. It is possible for a well to produce large volumes of gas through the tubing while the annular gas flow rate is zero. Typically these wells are producing with a bottom hole pressure greater than the bubble point pressure of the oil.

Whenever the producing bottom-hole pressure is less than the bubble point pressure of the reservoir oil, both gas and liquid will flow through the perforations and upwards to the pump intake. The higher the annular gas flow rate the greater the concentration of gas in the annular fluid column and thus at the depth of the pump intake. Therefore if the pump intake is set above the perforations and an efficient downhole gas separator is installed the concentration of liquid in the pump barrel at the top of the stroke should be greater than the percentage of liquid that exists in the casing annulus at the depth of the pump intake. Also in the case of a natural downhole separator when the pump intake is set below the bottom of the perforations, the percent liquid fillage in the pump should be greater than the concentration of liquid in the annulus at the depth of the perforations. These criteria can be used to evaluate the efficiency of downhole gas separators operating in different wells outfitted with rod pumps.

An extensive series of measurements were undertaken in 27 wells in the Permian Basin that included 14 completions with the pump intake set below perforations and 13 wells using packer type separators. For each well both fluid level and dynamometer records were acquired over a period of several weeks and analyzed in detail to verify the quality of the data and eliminate the possibility of mistakenly include data from wells exhibiting poor pump fillage due to pump-off or intake obstruction.

Figure 3a shows fluid level and dynamometer data corresponding to one of the wells that was outfitted with a packer-type separator. The pump is set above the perforations; annular gas flow of 511 MSCFD creates an annular gaseous liquid column with 19% liquid resulting in a pump intake pressure of 521 psi. The pump dynamometer record shows a characteristic gas interference pattern with a liquid pump fillage of about 62%. These values are combined with the results of previous acoustic and dynamometer records for this specific well to calculate an average performance over the period of time studied. The average pump liquid fillage and the average liquid concentration at the depth of the pump intake are cross-plotted in the figure as shown by the arrows pointing to the red dot. For the specific well conditions the packer type separator increased the liquid concentration from 19% in the annulus to 62% in the pump. Similar record analysis and calculations were performed for all the other wells with packer type separators and plotted as red dots. For the wells completed with the pump intake located below the perforations or in the “rat hole” the average values are shown as triangle points in the expanded view Figure 3b. The red line indicates the boundary where the liquid fillage equals the liquid concentration in the annulus. Points to the right and below the red line correspond to an increase in liquid concentration inside the pump while points to the left and above the red line indicate that the pump liquid fillage is less than the concentration of liquid that was present in the

annulus. That is, points above the line indicate that the presence of the separator was detrimental to the pump liquid fillage.

Since the majority of the triangles, that represent natural separators, are located in the region where pump liquid fillage is greater than the liquid concentration in the annulus it shows that locating the pump intake below the perforations is the best method for obtaining good pump volumetric efficiency. The point indicated by the large open triangle represents the average liquid fillage (86%) for all the pumps located in the rat hole while the large open circle corresponds to the average liquid fillage (62%) for all the pumps using a packer type separator.

Possible reasons for the inferior performance of the conventional packer type separators are attributable to designs that do not consider the effect of pressure drop on the evolution of gas from the liquid and disregard the need for large flow areas and minimum pressure drop between the separator entry point and the pump intake.

Using the liquid pump fillage as a parameter to evaluate the performance of a downhole gas separator needs to be applied with care since the advent of specialty pumps that are designed to eliminate fluid pound by filling the pump barrel with liquid from above the plunger rather than through the standing valve. These special pumps include using large clearances between the plunger and barrel, using gas vent holes, using tapered extensions of the pump barrel or using mechanical devices to unseat the traveling valve. These arrangements are effective in reducing the detrimental impacts to the rods caused by fluid pound but simultaneously reduce the volumetric efficiency of the pump. The pump barrel is filled in part with the liquid flowing from the bottom of the tubing so that a smaller volume of liquid is transferred from the casing to the tubing through the standing valve and delivered to the surface. In some extreme cases, although the pump is filled 100% with liquid at the top of the plunger stroke, practically no fluid is drawn into the pump through the standing valve and produced at the surface. The efficiency of a downhole gas separator that is used with one of these pumps cannot be established by considering the liquid fillage of the pump in relation to the concentration of liquid existing in the annulus. The actual liquid production rate must be evaluated.

Optimized Down-Hole Packer Type Gas/Liquid Separator

The objective of a packer type downhole gas separator is to reproduce as closely as possible the flow characteristics that could be achieved if the pump intake were located below the bottom of the perforations, that is:

- Use the full annular area between the casing ID and the tubing OD to minimize the downward velocity of the liquid
- Provide direct access between the fluid in the annulus and the pump intake
- Minimize pressure losses due to flow through restricted passages
- Allow free flow of the gaseous phase to the top of the annulus

These four principles were combined with the results of the field evaluations and with laboratory studies of separator performance to develop an optimized packer type separator that would maximize the liquid concentration flowing into the pump intake. The resulting design is shown schematically in Figure 4 that illustrates the main features of the improved design including:

1 - An integral pump seating nipple that is located at the bottom of the gas separator so that the pump inlet is adjacent to the liquid accumulated in the casing-separator annulus.

2 – Concentric design so that the OD of the separator is nearly identical to the OD of the tubing.

3 – A packer or diverter cups that are located at the bottom of the separator with a tubing anchor/catcher located below the packing assembly.

4 – A single fluid outlet from the top of the separator so that fluid flow impinges on the casing wall spreading the liquid into a film with circular downwards motion to facilitate gas/liquid separation.

5 – Means for attaching a tail pipe to the bottom of the assembly of adequate length and diameter to minimize the multi-phase flow gradient between the separator and the producing formation.

All of the formation fluids are directed into the bottom of the separator and flow upwards through a large area inside the separator and are discharged horizontally at the top impinging on the casing wall which enhances gas-liquid separation. The discharged liquid falls down the casing annulus to the pump inlet while the separated gas flows freely upwards towards the casing head.

Operational Considerations

Packer type separators have been in use for many years. Normally it is considered that their application should be limited to wells where production of solids is minimal in order to reduce the potential of mechanical problems when the tubing has to be retrieved. This concern was taken into account in the design of the optimized separator by minimizing the distance between the top of the packing element and the pump inlet so that the volume of solids that may settle in this part of the annulus is relatively small. In addition by locating the pump seating nipple in the immediate vicinity of the top of the packing element reduces the volume of solids that may accumulate inside the separator cavity.

In addition, the accumulation of sand or debris above the packer 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 accumulated in the tubing above the pump. This procedure 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 into the annulus where the solids are accumulated 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 packer. The discharging liquid will flow up the casing annulus and carry the solids. Probably $\frac{1}{2}$ of the liquid and solids will also flow down through the gas separator into the lower portion of the casing below the packer and fall to the bottom of the well. If necessary, additional flushing can be achieved by dumping more liquid down the tubing and through the separator. 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.

Field Experience

At the time of writing this paper several field tests are underway to evaluate the performance of the optimized packer type separator. Figure 5 shows the results of one such application where the liquid concentration of 20% existing in the annulus has been increased to a pump liquid fillage of 74 %. Note that based on Figure 3 this fillage is better than the average of other downhole packer type separators (62%) and lower than the average performance (86%) of installations with the pump in the rat hole.

Figure 6 is a graph of total liquid and gas production of this well from time of installation of the separator through almost one month of operation. A second well has been outfitted with the optimized separator and exhibits a similar performance. Results of additional field tests will be included in the presentation that will be given at the conference.

Conclusions

The performance of downhole gas/liquid separators can be established consistently by applying the criterion of comparing the pump fillage determined from pump dynamometer analysis with the liquid percentage present in the annulus at the pump intake determined from fluid level analysis as shown in Figure 3a.

A study of average pump fillage in 27 wells indicates that installing the pump intake below the bottom of the perforations results in higher liquid fillage than using existing designs of packer type separators.

Results of field and laboratory studies have been applied to designing an optimized packer type gas/liquid separator that includes the pump landing nipple in order to minimize pressure drop between the fluid entry point and the pump intake.

Initial field tests of the optimized separator indicate that its performance is better than the average performance of existing packer type separators.

Tables

	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. Flow rate based on limiting the liquid velocity to 6 inches/second.

Figures

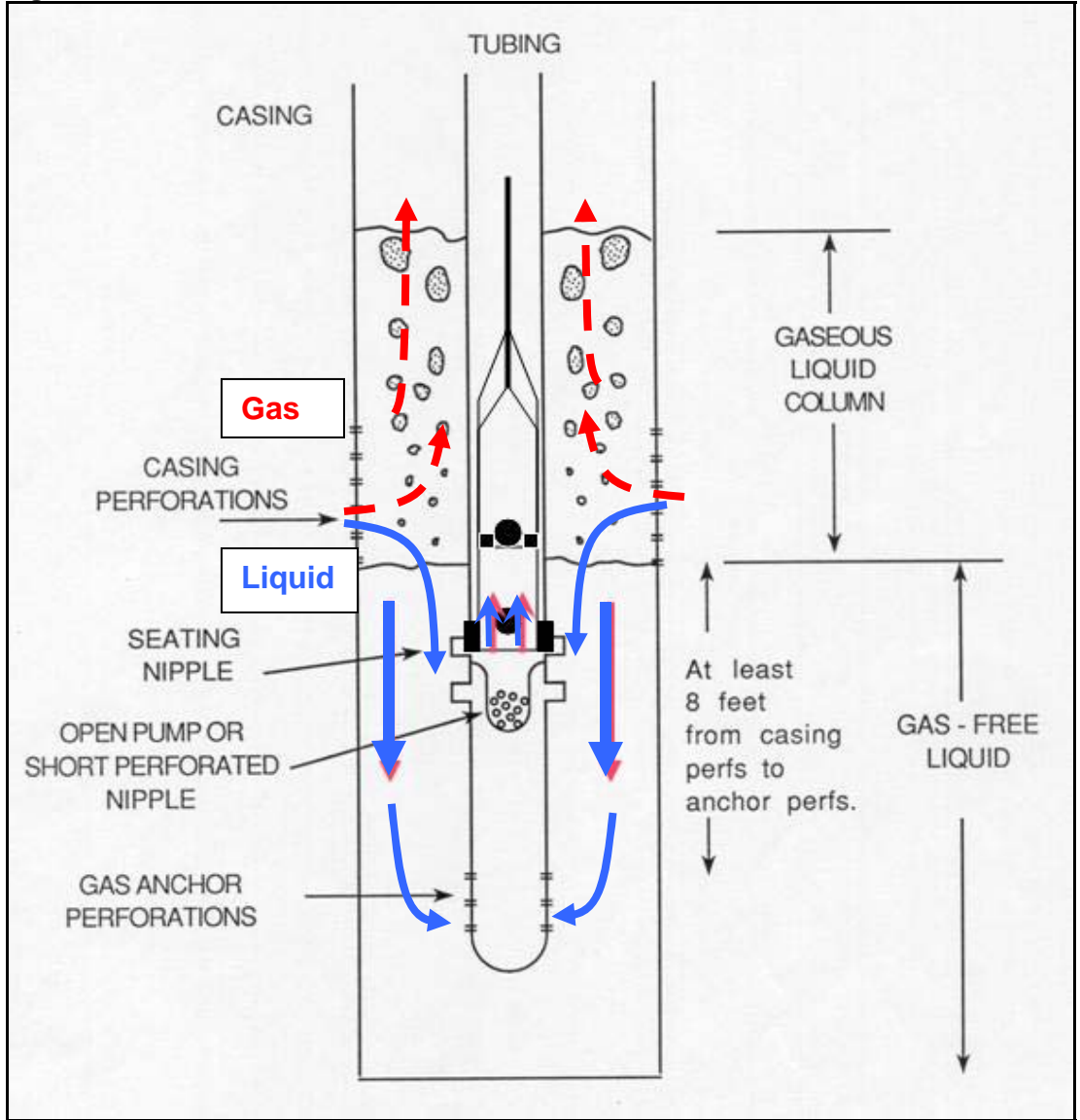


Figure 1 – Flow Path in a Natural Gas-Liquid Separator with Pump Intake Set Below Perforations

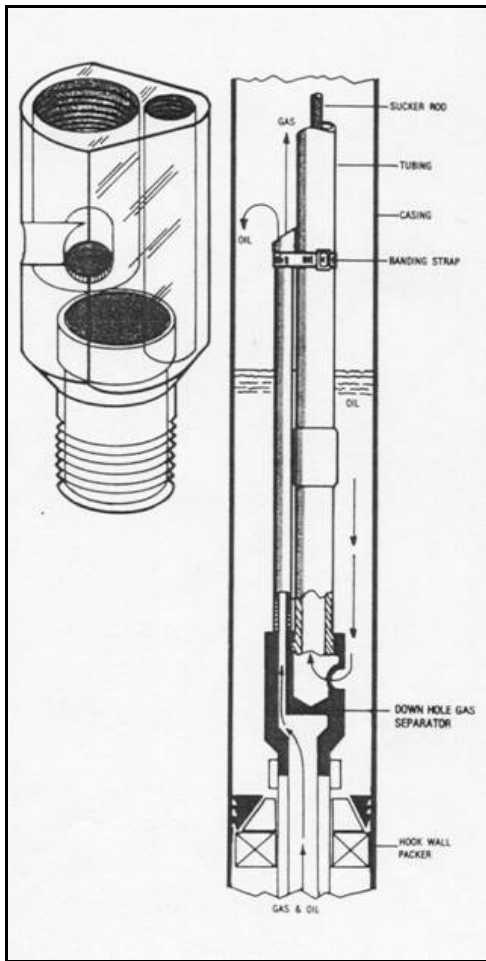


Figure 2 A - Packer Type Separator with Riser²²

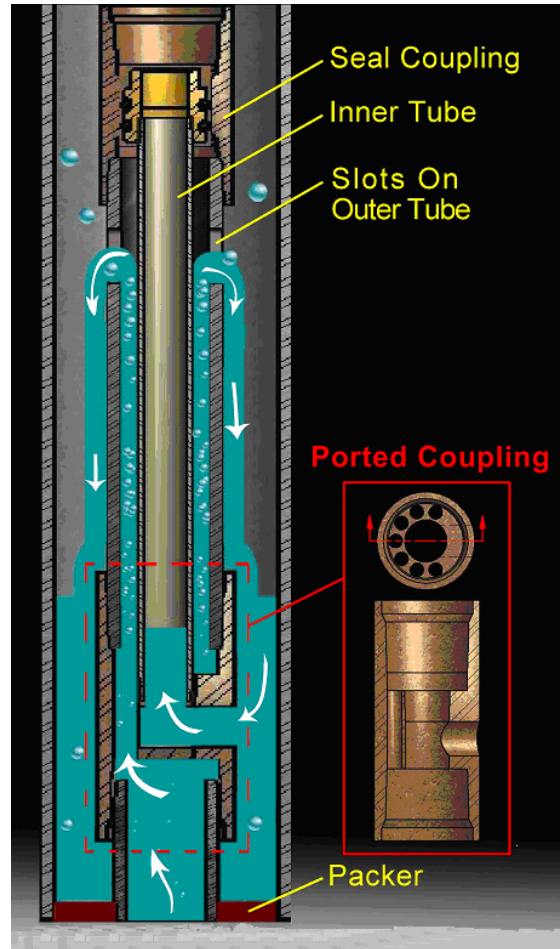


Figure 2 B - Concentric Packer Type Separator²³

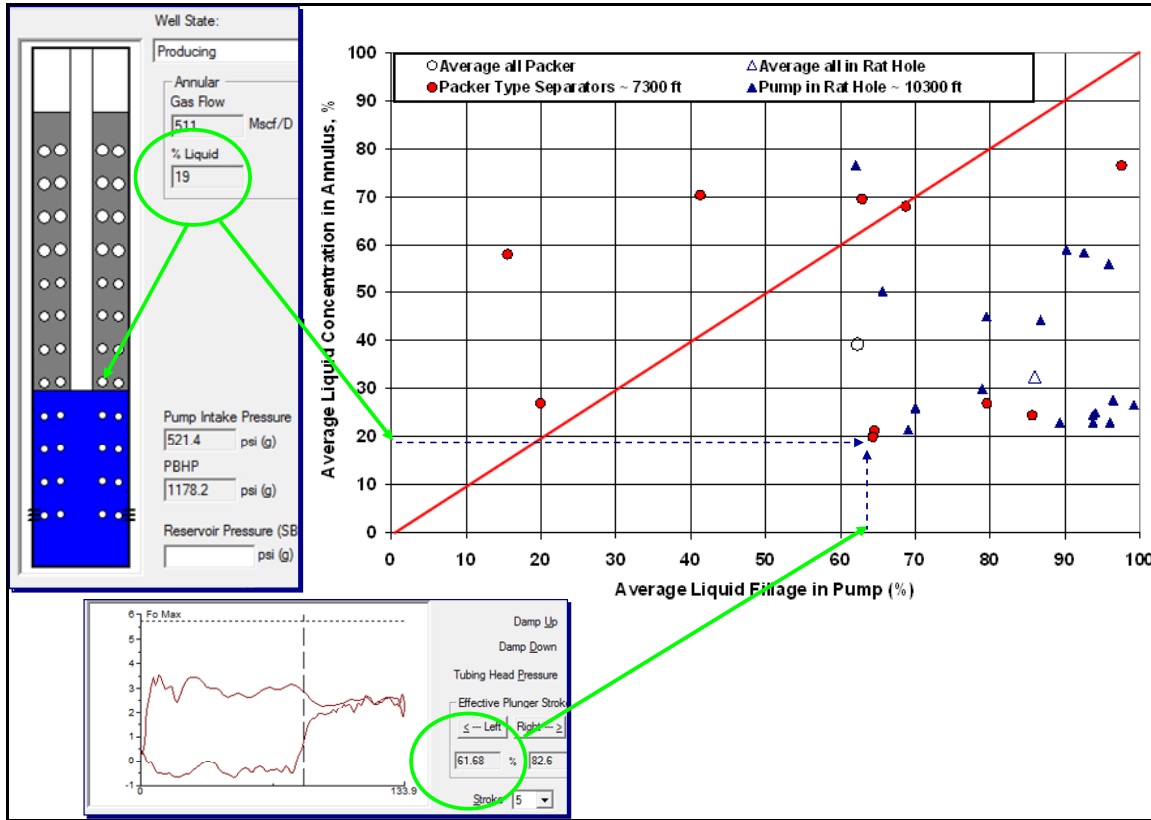


Figure 3a – Determination of Separator Performance from Fluid Level and Dynamometer Tests.

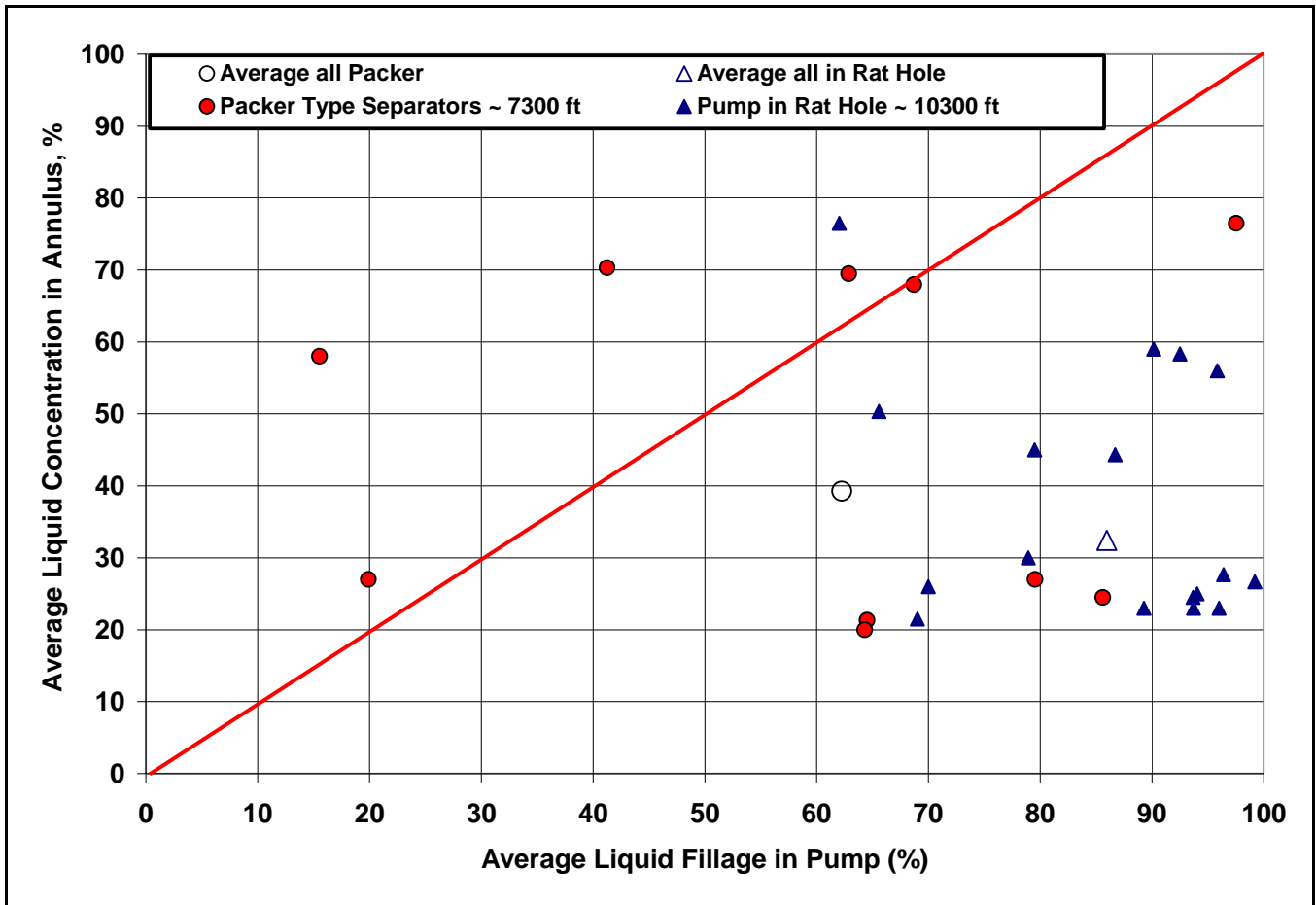


Figure 3b – Comparison between Pump Liquid Fillage and Liquid Concentration in Annular Gaseous Liquid Column. Data from fluid level and dynamometer tests in 24 wells.

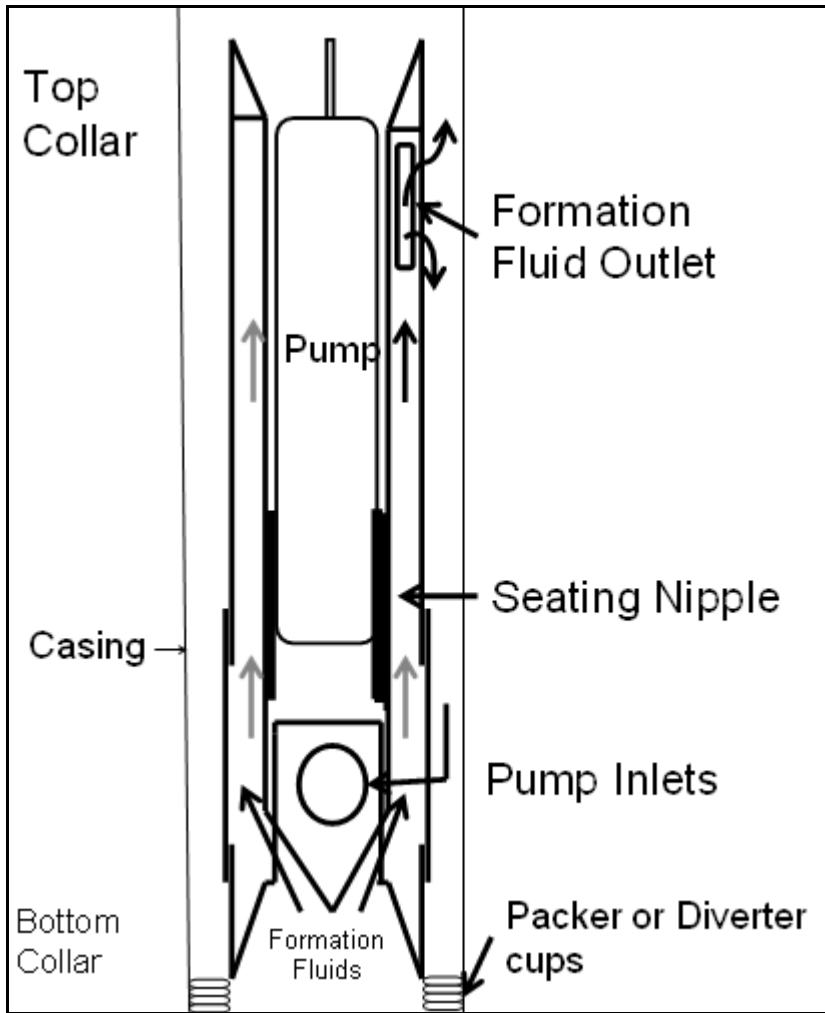


Figure 4 – Optimized Design for Packer Type Separator

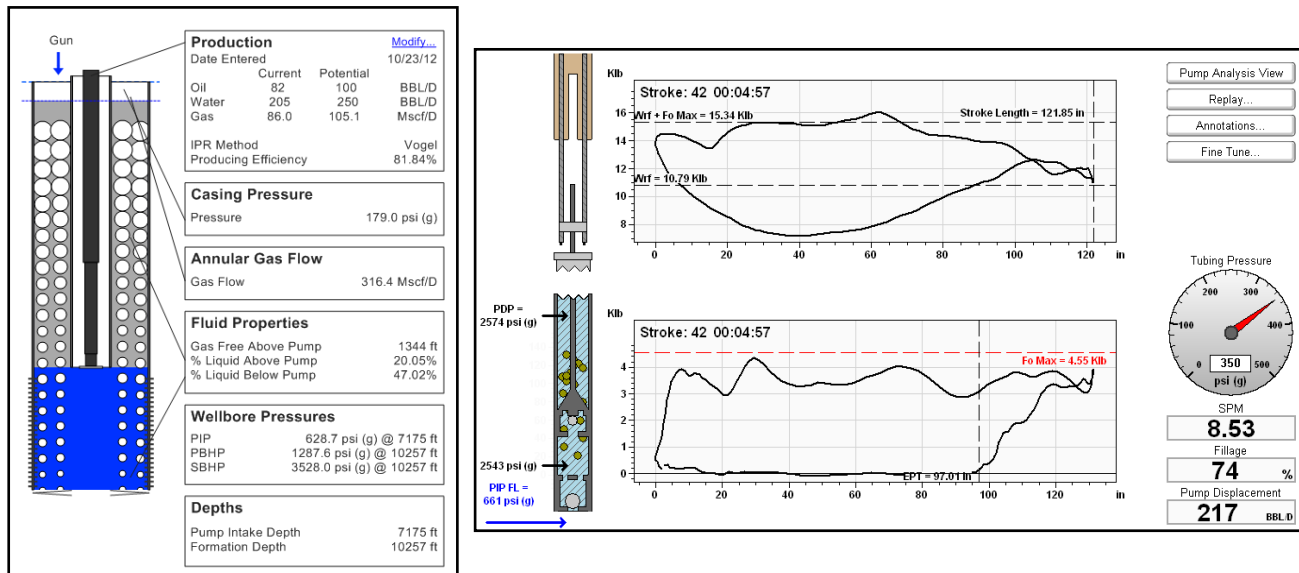


Figure 5 – Sample Performance of the Optimized Packer Type Separator

Well Production Performance with Optimized Packer Type Separator

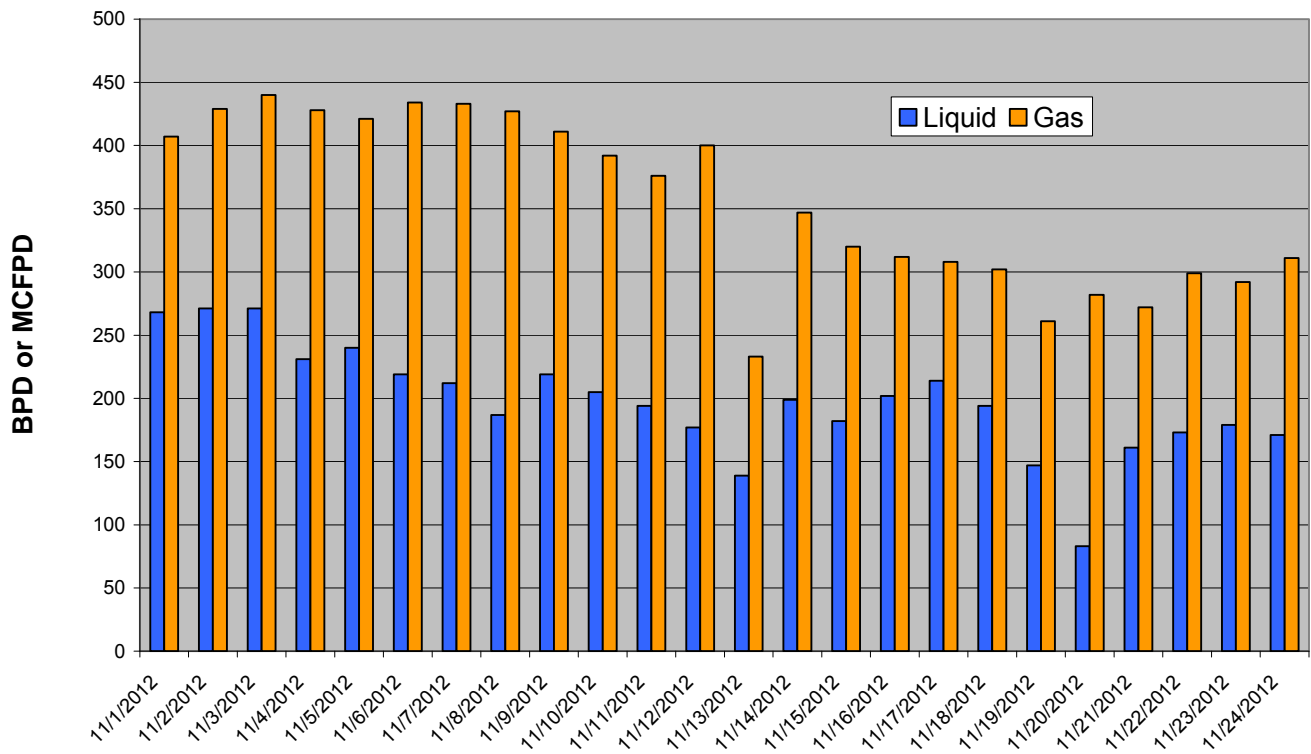


Figure 6 – Production History for Well Corresponding to Figure 5 since Installation of the Optimized Packer Type Separator

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