Unique Chamber Gas Lift Performance

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INTRODUCTION

Numerous articles have been written on the utilization of chambers for gas lift operations. However, continued research and field application have shown chambers to be capable of performing beyond previous expectations. It is the purpose of this article to give a brief review of chamber application and design and in particular to show some actual field installations that have done exceptional jobs.

The chamber installation is best suited for a well having a high productivity index and a low to medium bottom hole pressure. It is sometimes quite difficult to determine whether a chamber is necessary as compared to a straight intermittent tubing installation.

In turn it may also be somewhat difficult to determine whether or not a well should be placed on intermittent lift or continuous flow. However, reliable flowing gradients for multiphase flow allow accurate predictions for flowing bottom hole pressures for particular liquid flow rates and gas liquid ratios. It is quite easy to establish the average flowing bottom hole pressure which can be maintained for continuous flow. If this exceeds the pressure necessary to allow ample feed-in according to the wells productivity index then an intermittent installation should be considered. In turn an additional analysis must then be made to determine an average flowing bottom hole pressure for a straight tubing intermittent installation. If this is still excessive to allow the desired liquid feed-in then a chamber installation should be considered.

Unique Chamber Gas Lift Performance

If there exists a doubt about whether a chamber is necessary on a borderline well, a chamber should be installed on the original installation. The additional cost of a chamber is not enough to risk the possibility of not needing such an installation. Of course, there are some wells in which it is not advisable to run a chamber installation because of well hazards such as corrosion and or sand. However, chambers have proved beneficial in some instances for sand production. This is duscussed further in the text of this paper.

Also, chambers have been installed in wells with high bottom hole pressures and high gas liquid ratios (California) and are found to out-perform other types of installations.

In particular chambers have done almost unbelievable jobs in some instances. Specific examples show production in the neighborhood of 500-700 BD from depths of 6500 ft.

TYPES OF CHAMBERS

There are 2 general types of chamber installations. Figure 1 shows a typical two packer chamber installation while Figure 2 shows an insert chamber installation.

Both types have advantages and disadvantages. Generally the type of well completion determines the type of chamber to install.

The 2 packer chamber makes use of the casing annular space for the accumulator. Its advantage is that it offers maximum storage space per unit of length. However, the bottom packer must always be set immediately above the perforated interval or open hole completion.

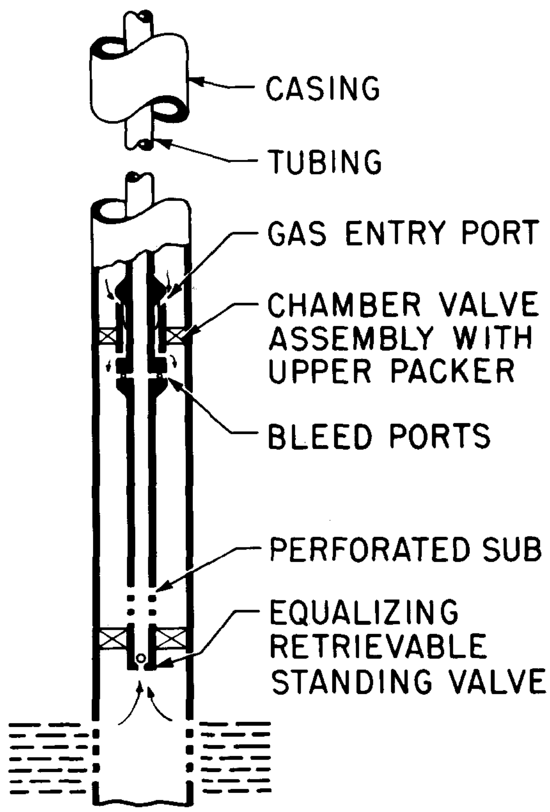


FIG. I. TYPICAL TWO-PACKER CHAMBER INSTALLATION.

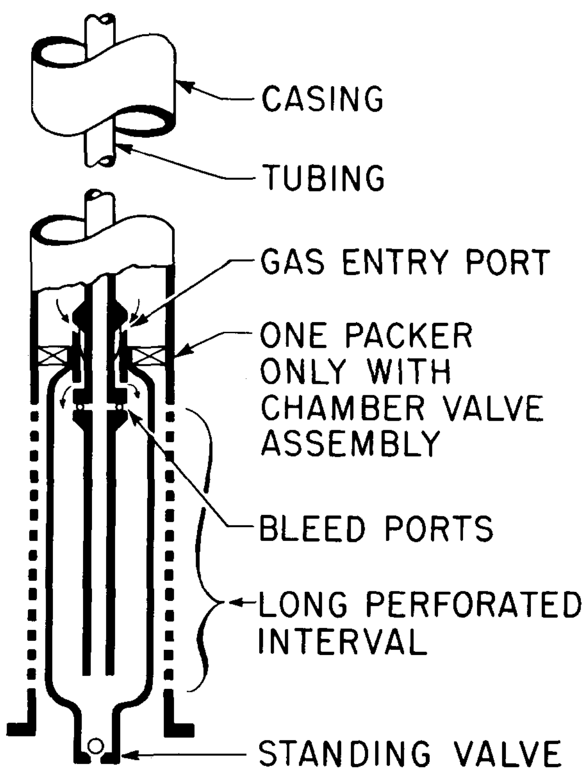


FIG. 2. TYPICAL INSERT CHAMBER INSTALLATION.

The insert chamber is made from pipe (preferably streamlined) and inserted into the well. Its advantage is that it may be inserted into an open hole completion or long perforated interval. Therefore, a chamber of this type takes full advantage of the input flow characteristics of a very low bottom hole pressure well.

CHAMBER OPERATION

Reference should be made to Figure 1 in order to follow the sequence of events in a chamber operation: Assume that the cycle is started with a head of liquid just being produced at the surface:

1. The standing valve is open and fluids are entering into the accumulation chamber as well as the tubing string.
2. The bleed valve is open (normally open with a low differential across it) and is allowing gas to escape from the chamber into the tubing string.
3. Fluids continue to feed in through the standing valve until the chamber is filled to the desired level. If the chamber has been designed properly the liquid level should be near the bleed valve or ports. Gas has continued to escape through the bleed valve. This bleed valve is an extremely important part of the chamber installation. It can be the life of the chamber, in particular for high solution GOR wells.
4. As the chamber is filled the operating gas lift valve opens and allows a calculated gas volume to enter on top of the accumulated liquid in the chamber. This immediately closes the bleed valve and the standing valve.
5. The accumulated liquid is U-tubed from the chamber into the tubing string.
6. The accumulated liquid is produced out at the surface with the bleed valve remaining closed until the liquid has entered the tubing string. This valve may reopen before the slug is completely removed but does no harm in this respect.
7. As the tubing is cleared, the standing valve reopens and liquids again refill the chamber. The bleed valve is again open, allowing gas to escape.
8. The cycle again repeats itself.

WHEN DO YOU INSTALL A CHAMBER INSTALLATION?

In a report by Brown and Jessen [1] a means for calculating a weighted average bottom hole pressure was given for a straight tubing intermittent installation. This was also mentioned in a paper by Beadle, Harlan, and Brown at the fall meeting of the SPE of AIME in Los Angeles. If it has been determined that a well is to go on intermittent lift, an attempt should be made to calculate the weighted average bottom hole pressure

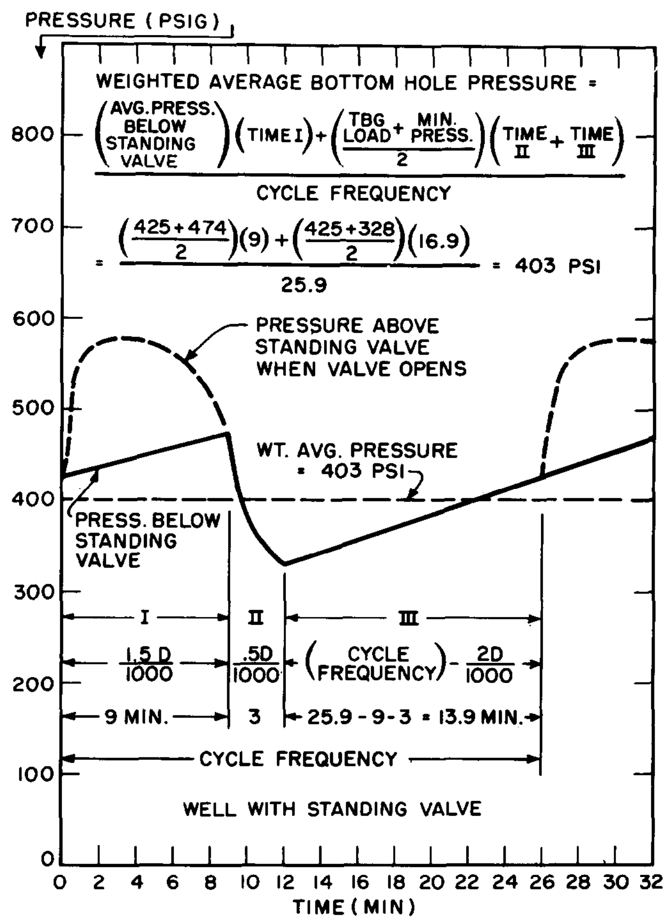


FIG. 3. WEIGHTED AVERAGE FLOWING BOTTOM HOLE PRESSURE WITH STANDING VALVE.
Reproduced from AIME and Reference 1

as shown in Figure 3. If it can be shown that the average flowing pressure is too great to allow the desired production rate, then a chamber installation must be considered. Although a chamber may not show any increase in production over a straight tubing installation, a decrease in the injection gas liquid ratio is generally noted.

CALCULATION OF THE WEIGHTED AVERAGE FLOWING BOTTOM HOLE PRESSURE

Reference should be made to Figure 3 which shows calculated weighted average bottom hole pressure for the example well as mentioned in references 1 and 2. Since this procedure involves several pages of calculations it is not presented here but will be made available to anyone desiring it.

Briefly, the weighted average bottom hole pressure can be calculated by the following procedure (A detailed example can be obtained by contacting Dr. K. E. Brown, Dept. of Petroleum Engineering, The Univ. of Texas):

1. Determine the minimum pressure created during an intermittent cycle. Since the minimum pressure occurs before all the fall-back has settled in the tubing string, and after well feed-in has begun to occur a difficult solution arises. The minimum pressure is a function of (a) the tubing back pressure accounting for its gas column weight to the top of the slug, (b) the non-produced portion of the liquid slug (fall-back), and (c) the amount of liquid that has been produced into the tubing string by the time the minimum pressure has occurred. This is further complicated by the input flow characteristics of the well itself. In reality the formation fluids are still feeding towards the well bore even though the standing valve is closed.
2. Determine the maximum pressure created at the sand face and the length of time for which this occurs. This differs depending upon whether or not a standing valve has been installed and occurs when the slug is traveling to the surface.
3. Determine the rate of build-up of pressure from the well input flow characteristics. This information may or may not be available.
4. From the previous information, the best cycle frequency can be determined as well as the average flowing bottom hole pressure.

If it is found that the weighted average flowing bottom hole pressure is in excess of that pressure which allows the desired drawdown and in turn the desired production, then a chamber installation should be installed. It is quite obvious why a chamber will reduce the weighted average flowing bottom hole pressure. The main contribution to the lowering of this average pressure is that the liquids feed into the accumulation chamber as compared to feeding into the tubing string for a straight tubing installation. For example, if a 4 bbl slug of .40 psi/ft liquid is allowed to accumulate in 2-3/8 in. OD tubing as compared to one annulus of 2-3/8 in OD tubing in 5-1/2 in. - 17 lb/ft casing the respective heights of liquid rise would be 1033 ft and 184 ft. These heights in turn would exert pressures of 413 psi and 74 psi respectively. A difference of 339 psi would then occur because of the hydrostatic head of the liquid alone. This means that the average flowing bottom hole pressure can be maintained at a much lower value with the chamber installation. Although a chamber may not be necessary at the time of the original installation a prediction of the future bottom hole pressure may show the need of a chamber in the near future. If so, it would be advisable to install the chamber at the time of the original installation.

DESIGN PROCEDURE FOR A CHAMBER

The actual design of the chamber is fairly simple, but should be treated with caution. The following will serve as a step-wise procedure for the design of a chamber installation:

1. Decide from well completion information the type of chamber desired.
2. Select the pressure of the operating valve. The pressure setting on the operating valve and the length of the chamber will be influenced by 2 limitations; the gas injection pressure available, and the rate of fluid feed-in into the well bore.

   If information is available from a pressure build-up curve, then this should give an idea as to the size of chamber needed. Probably all that will be known will be the static bottom hole pressure. Since chambers are best suited for high P.I. wells, it is likely that the well will feed in at a fast rate for 50% to 75% of the static pressure. Actually it is better to have the chamber too long rather than too small.

   If there is a limit as to injection gas pressure available, this this automatically takes care of the size of chamber to use. The setting pressure on the operating valve should definitely be high enough not to be overloaded under any fluid condition.
3. Allow 100-150 psi differential between the total load in the tubing and the opening pressure of the operating gas lift valve.
4. Convert the tubing load in psi to bbls of liquid.
5. Select a chamber size to hold this amount of liquid.
6. Select a differential valve (spring loaded) for the bleed valve or port. In cases of high gas liquid ratios a special bleed assembly should be utilized. It is important that the differential on this valve not be set too high. For low operating pressures it may be advisable to set this differential as low as 25 psi.
7. Space the unloading valves. The spacing of the unloading valves may also influence the pressure of the operating valve.
8. Be sure the unloading valve immediately above the chamber valve is not spaced too far above the top of the chamber. This is important since a stymied condition could easily occur.
9. Back check the surface opening pressures of all valves, and also determine the actual opening pressure opposite the operating valve.

SPECIAL APPLICATIONS

Chamber Installation for Sand Production

In many instances sand production is a serious detriment to good artificial lift operations. This is true regardless of the type of artificial lift employed. If the well condition is such that the screening of sand is quite difficult, the only alternative may be to produce the sand.

Reference is made to Figure 4 which shows a method used in chamber lift in a bad sand well. This method of lift proved to be successful whereby all other methods failed in several instances. A straight tubing intermittent installation was successful only if a gas lift valve was used such that no impingement of fluids was caused by the direction of gas entry. A direct blasting of sand mixed with fluids on the side of a tubing string resulted in less than one month's operation before a hole was blasted in the tubing string.

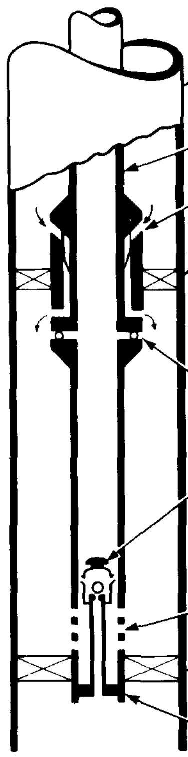


FIG. 4. SPECIAL INSTALLATION FOR HANDLING SAND.

Figure 4 shows the standing valve as being extended above the bottom packer and into the top perforated nipple.

Also as noted it is desirable to keep the top perforated nipple as close as possible to the top of the bottom packer. As fluids enter the chamber through the standing valve the sand will have a tendency to settle back. With the extended standing valve there is ample space for the sand to settle around the standing valve extension without plugging the standing valve. Also, sand will settle back on top of the top packer. However, once gas is injected the washing action of the produced fluids through the perforated nipple will clean the sand from around the standing valve extension as well as from around the top of the packer. This installation has proved to be successful in some instances in which other installations have failed.

Deep Chamber Lift

It is known that wells in the neighborhood of 10,000 ft or deeper offer lifting problems that are difficult for any type of artificial lift. The chamber gas lift installation serves as one of the better types of lift for a well of this depth. The information on an actual installation at 10,000 ft is given as follows:

A well in South Central Oklahoma presented the fwollowing problem. This well had perforations at 8734 ft to 8781 ft and lower perforations at 10,083 ft to 10,116 ft. The casing size was 7 in. - 23 lb/ft and the tubing was 2-7/8 in. EUE. It was desirable to pack off the upper zone and to produce the lower zone with maximum production. Reference should be made to Figure 5 which shows the final arrangement of equipment in the well. It was decided to pack-off the upper zone with 2 packers but allow gas to bypass both packers to be able to chamber gas lift the lower zone. A standard 2 packer chamber was installed on the bottom zone. A production test showed the lower zone to be producing 440 BFPD from 10,000 ft with 580 psi operating gas pressure. This was accomplished with an input injection gas liquid ratio of 1700 SCF/bbl. This

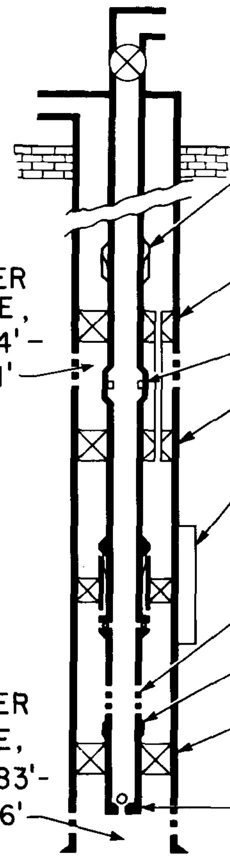


FIG. 5. SPECIAL BYPASS DEEP CHAMBER INSTALLATION.

installation has been performing satisfactorily for a period of approximately 8 months.

This particular chamber installation was equipped with special large bleed parts. This was necessary since a large volume of solution gas was expected. This special bleed valve was equipped with 4-1/2 in. parts which was ample to bleed off the trapped solution gas. This in turn allowed larger volumes of accumulated liquid per cycle and resulted in greater total liquid production per day.

To eliminate loss in production because of excessive surface back pressure caused by long flow lines, the separator was moved to the well site and the oil pumped on to the main battery.

High Productivity Chamber Lift

In an attempt to increase the oil production in a unitized field, it was decided to try gas lift chambers to see if production could be increased over prior artificial lift methods. Most of the wells were making from 150 to 300 BOPD with no water. These wells are at an approximate depth of 6500 ft and are under water flood. The static pressure in most wells is approximately 1200 psi which places the reservoir oil below the bubble point. Being a unitized field these particular wells were being selectively produced, and in turn, were placed on field allowable which accounts for the high production rates.

Reference should be made to Figure 6 for a typical chamber installations as made in this field. Because of ample gas supply at 950 - 1000 psi, the chambers could be made to hold from 8 - 12 bbl slugs of oil. Figures 7 and 8 show typical 2 pen recordings

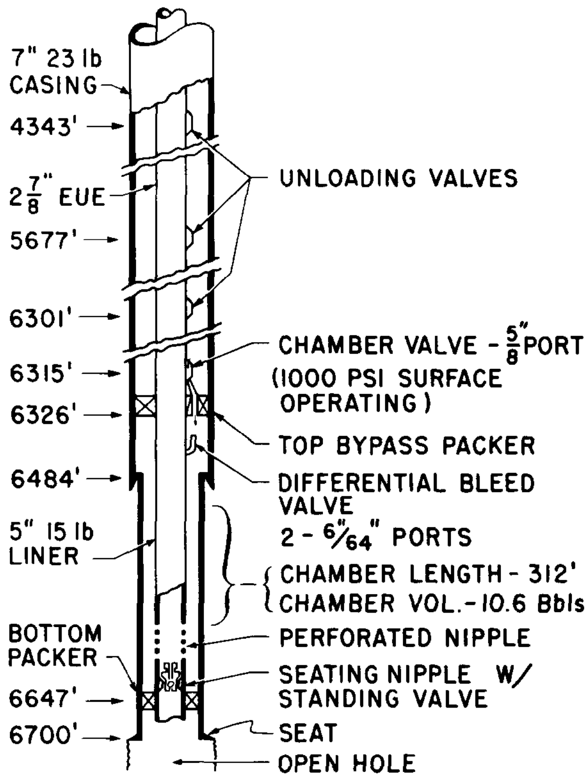
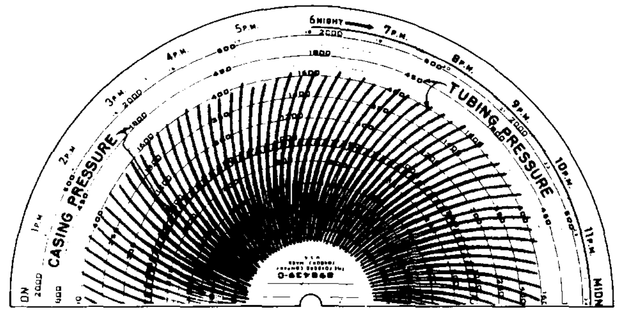
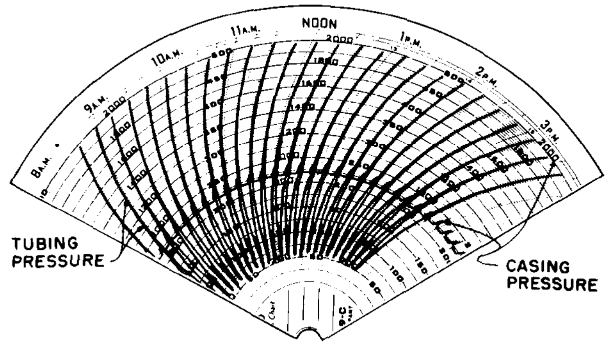


FIG. 6. TYPICAL CHAMBER INSTALLATION FOR HIGH PRODUCTIVITY WELLS (600 B/D)



7" CSG	12 MIN CYCLES
5" LINER	4.70 BBLS/CYCLE
$2\frac{7}{8}$" TBG	8 BBL CHAMBER
PROD - 565 BOPD	DEPTH - OPERATING
- 0 WATER	VALVE - 6274'
G/L - 1395/1	

FIG. 7. TYPICAL RECORDING OF CASING AND TUBING PRESSURE FOR HIGH PRODUCTIVITY CHAMBER PERFORMANCE.



7" CSG	15 MIN CYCLES
$2\frac{7}{8}$" TBG	6.65 BBLS/CYCLE
PROD - 639 BOPD	10 BBL CHAMBER
- 0 WATER	DEPTH - OPERATING
G/L - 1059/1	VALVE - 6315'

FIG. 8. TYPICAL RECORDING OF CASING AND TUBING PRESSURE FOR HIGH PRODUCTIVITY CHAMBER PERFORMANCE.

from 2 of these wells. The production was 639 and 565 BOPD respectively on these two tests with injection gas oil ratio of 1059 and 1395 respectively. The injection gas oil ratios have ranged from 1500 to as low as 600 SCF per bbl.

Reference to the tests as shown of Figures 7 and 8 indicates that production in the neighborhood of 600 BPD can be intermitted successfully from 6500 ft if ample gas pressure is available. It is generally conceded that normally you are not expected to be able to produce this much liquid from 6500 ft by intermittent gas lift but this was a situation that disproved this prior conception.

SUMMARY AND CONCLUSIONS

It has been shown by actual field tests that gas lifting with chamber installations is a very efficient means of producing oil at high rates from depths to 10,000 ft. Production rates of 600 BOPD were obtained from 6500 ft and 440 BOPD were obtained from 10,000 ft.

In addition, chamber installations have been used successfully to produce bad sand wells. If the standing valve is extended so that it is washed clean during each producing cycle the installation continues to function properly.

Chambers are a means of gas lift that are often over looked by an operator, and in many instances greater production rates with lower injection ratios can be obtained with chambers.

REFERENCES

1. K. E. Brown and F. W. Jessen. "The Vertical Flow of Liquid Slugs by Intermittent Gas Lift", Technical Report to Marathon Oil Company, (Formerly The Ohio Oil Company), Sun Oil Company, and Otis Engineering Corporation, May 1, 1962.

2. Glenn Beadle, John Harlan and K. E. Brown. "Evaluation of Surface Back Pressure for Continuous and Intermittent Flow Gas Lift," Journal of Petroleum Technology, (March, 1963).